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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

April 26, 2013

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

Dear Ms. Walli:

EB-2013-0187 – MAAD S86 Hydro One Inc Application to Purchase Norfolk Power Inc.

I am attaching two (2) copies of Hydro One Inc's MAAD Application for the acquisition of Norfolk Power Inc. The information that has been redacted in Exhibit A, Tab 3, Schedule 1, Attachment 6 contains customer, employee, property owner, and banking information. In addition we have redacted the names of the contractors and the environmental disclosures along with removing the Form of the Pole Purchase Agreement at the request of Norfolk County who believes this information is not relevant to the MAAD process, or because it contains confidential and/or commercially sensitive information.

Also attached is a letter of endorsement from Mark Rodger, counsel to Norfolk County, the sole shareholder of Norfolk Power Inc.

An electronic copy of the application has been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

attach

J. Mark Rodger
T (416) 367-6190
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Borden Ladner Gervais

April 25, 2013

Delivered by Courier and RESS

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2701
Toronto, ON M4P 1E4

Dear Ms. Walli:

**Re: Sale of Norfolk Power Distribution Inc. to Hydro One Networks Inc.
Applications under Section 86 of the Ontario Energy Board Act, 1998**

We are counsel to Norfolk County and Norfolk Power Inc. On April 2, 2013, following a comprehensive and competitive Requests For Proposals process, Norfolk County entered into a share purchase agreement to sell its electricity distribution company, Norfolk Power Distribution Inc., to Hydro One Networks Inc.

Norfolk Power Distribution Inc.'s customers will experience immediate benefits from this transaction. Among the benefits, the transaction will cause NPDI's distribution rates to be reduced by 1% upon closing and thereafter these distribution rates will be frozen at the reduced level for the next 5 years. The parties request that the Board give effect to this arrangement through the implementation of a new rate rider. The rate reduction/rate freeze issues are addressed in an appendix to the enclosed application at Exhibit A, Tab 2, Schedule 1, Section 2.0.

Norfolk County submits that the proposed transaction is consistent with and advances Provincial objectives around voluntary consolidation within the Ontario local distribution sector. Norfolk County also believes the distribution rate reduction/ rate freeze components of the transaction are consistent with recent statements of the Minister of Energy concerning "the need to "bend the cost curve" for ratepayers"[1].

Yours very truly

BORDEN LADNER GERVAIS LLP

J. Mark Rodger
Incorporated Partner*

[1] Remarks for The Honourable Bob Chiarelli, Minister of Energy, Ontario Power Conference, April 16, 2013, page 9

Borden Ladner Gervais

Copy to Dennis Travale, Mayor, Norfolk County
Al Hays, Chair, Norfolk Power Inc.
Jamie Waller, Hydro One Inc.
Michael Engelberg, Hydro One Inc.

*Mark Rodger Professional Corporation

TOR01: 5166668: v2

ONTARIO ENERGY BOARD

IN THE MATTER OF an application made by Hydro One Inc. for leave to purchase all of the issued and outstanding shares of Norfolk Power Inc. made pursuant to section 86(2)(b) of the *Ontario Energy Board Act, 1998*.

AND IN THE MATTER OF an application made by Norfolk Power Distribution Inc. for leave to transfer its distribution system to Hydro One Networks Inc. made pursuant to section 86(1)(a) of the *Ontario Energy Board Act, 1998*.

AND IN THE MATTER OF an application made by Norfolk Power Distribution Inc. seeking cancellation of its distribution licence made pursuant to section 77(5) of the *Ontario Energy Board Act, 1998*.

AND IN THE MATTER OF an application made by Hydro One Networks Inc. seeking an order to amend its distribution licence made pursuant to section 74 of the *Ontario Energy Board Act, 1998*.

AND IN THE MATTER OF an application made by Hydro One Networks Inc. seeking to include a rate rider in the 2013 OEB-approved rate schedule of Norfolk Power Distribution Inc. to give effect to a 1% reduction relative to 2012 base electricity delivery rates (exclusive of rate riders), made pursuant to section 78 of the *Ontario Energy Board Act, 1998*.

APPLICATION

The Applicant under section 86(2)(b) of the *Ontario Energy Board Act, 1998*, is Hydro One Inc.(“HOI”), an Ontario corporation with its head office in the City of Toronto. HOI is wholly owned by the Province of Ontario and is the parent company of Hydro One Networks Inc.

("HONI"), Hydro One Brampton Networks Inc., Hydro One Remote Communities Inc. and Hydro One Telecom Inc.

The Applicant under section 86(1)(a) of the *Ontario Energy Board Act, 1998*, is Norfolk Power Distribution Inc. ("NPDI") a wholly owned subsidiary, at the date of this application, of Norfolk Power Inc. ("NPI"), NPI is a holding company, currently wholly-owned by The Corporation of the County of Norfolk ("the County"). Upon closing of the transaction, NPDI will be wound up and its assets transferred to HONI.

NPDI's distribution system serves approximately 19,000 Residential and General Service customers in the NPDI service territory (see **Exhibit A, Tab 3, Schedule 1, Section 1.3.3** for further customer details).

HONI's distribution system serves approximately 1.2 million customers in its service territory (See **Exhibit A, Tab 3, Schedule 1, Section 1.3.3** for further customer details).

1.0 OVERVIEW OF APPLICATION

On April 2, 2013, the County (as Vendor) and HOI (as Purchaser) entered into a share purchase agreement (the "Agreement"), whereby the Vendor agreed to sell, and the Purchaser agreed to purchase, all of the issued and outstanding shares of NPI (the "Shares"). The purchase price is $93 million, comprising a cash payment of approximately $66 million for the shares and the assumption of NPI's long-term debt of approximately $27 million. The Agreement contemplates the transaction closing 30 days following the Parties' receipt of all Required Approvals, including Ontario Energy Board ("the Board" or "OEB") approval of this application under sections 86(2) and 86(1) of the *Ontario Energy Board Act, 1998*.

The Agreement (see **Exhibit A, Tab 3, Schedule 1, Attachment 6**) contemplates the following items in addition to the sale of the Shares:

(a) The purchase price is subject to adjustment within 90 days following closing, for Working Capital, Net Fixed Assets, and Long Term Debt, as defined in the Agreement;

(b) As part of this Application, HONI will apply to the OEB for approval to include a negative rate rider to NPDI's electricity rates (effective May 1, 2013) to reduce base delivery distribution rates by one percent (1%) of the EB-2011-0272 approved 2012 rates, and to have such reduced rates apply for the next five years (see **Exhibit A, Tab 2, Schedule 1, Section 2** for further detail). Assuming such approval is obtained, it is HONI's current expectation that NPDI rates will be harmonized with HONI rates at the earliest rebasing opportunity, currently expected to be in 2020;

(c) HOI or an affiliate shall offer all employees of NPI and NPDI continued employment; and

(d) HOI and The County shall establish an advisory committee, which shall include at least three representatives from the County, to monitor and provide input with respect to the provision of distribution services in Norfolk County.

2.0 OEB APPROVAL REQUESTS

2.1 Ontario Energy Board Act, Sections 86(2)(b), 86(1)(a), 77(5) and 74 approvals

- HOI is applying to the Board pursuant to section 86(2)(b) of the *Ontario Energy Board Act, 1998* ("the Act"), seeking leave to acquire all the issued and outstanding shares of NPI from the County.

- NPDI is applying pursuant to section 86(1)(a) of the *Ontario Energy Board Act, 1998,* to dispose of its distribution system to HONI.

- If the Board grants leave for NPDI to dispose of its distribution system to HONI, upon closing of the proposed transaction, NPDI requests, pursuant to section 77(5) of the Act, that its electricity distribution licence be cancelled. HONI requests, pursuant to section 74 of the Act, that its Distribution licence be amended such that Appendix B, Tab 1 of its licence includes the portion of Norfolk County formerly served by NPDI and that Appendix B, Tab 4 be amended to exclude the portion of Norfolk County formerly served by NPDI.

- Immediately following the acquisition of the shares of NPI by HOI, HOI will transfer the assets and liabilities of the electricity distribution business from NPDI to HONI. If these applications are approved, the distribution system assets of NPDI will move directly from control by the County to direct ownership by HONI. NPDI will be wound up, and the former NPDI will carry on business as HONI NP until rate harmonization occurs.

- The net book value of the assets that will be transferred to HONI Distribution's rate base is approximately $53.9 million.

2.2 Other Approvals Sought

- HONI Distribution requests approval to include a rate rider in the 2013 OEB-approved rate schedule of NPDI to give effect to reducing the approved 2012 base delivery distribution rates (EB-2011-0272) by one per cent (1%). See **Exhibit A, Tab 2, Schedule 1, Section 2.0** for further information.

- HONI Distribution requests approval to defer the rate rebasing of HONI NP (the former NPDI) for five years from the date of closing the proposed transaction, consistent with the Report of the Board titled "Rate-making Associated with Distributor Consolidation" issued July 23, 2007. At the end of the five-year period, HONI Distribution expects to apply under the Board's Incentive Regulation Mechanism ("IRM") to adjust HONI NP's rates until the earliest opportunity to rebase its rates along with HONI Distribution rates, currently expected in 2020. See **Exhibit A, Tab 2, Schedule 1, Section 3.0** for further information.

- HONI Distribution requests approval to continue the "Application for Tax Changes" rate rider currently approved for NPDI until HONI NP's rates are rebased, and to true-up that balance at the next rebasing. See **Exhibit A, Tab 2, Schedule 1, Section 4.0** for further information.

- HOI requests approval to utilize USGAAP for HONI NP financial reporting.

SUPPLEMENTARY TRANSACTION INFORMATION

This exhibit provides evidence related to the impact of the proposed transaction with respect to price, adequacy, reliability and quality of electricity service, promotion on economic efficiency and cost effectiveness, and further details on approvals sought with respect to customer rates and bill impacts, timing of rebasing, regulatory assets and riders, USGAAP and compliance matters.

1.0 CONSUMER PROTECTION

Section 1 of the *Ontario Energy Board Act, 1998,* requires that the Board, in carrying out its responsibilities, shall be guided by the objectives, among others, to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service, and the promotion of economic efficiency and cost effectiveness. These principles and the "no harm" test were applied in granting leave in the section 86 applications, RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257, which established the scope of issues that the Board will consider in determining applications under section 86 of the Act.

1.1 Price, Adequacy, Reliability and Quality of Electricity Service

The proposed transaction protects NPDI's customers through a commitment to freeze their base electricity distribution delivery rates for a period of five years from closing of this transaction. In addition, HONI is seeking approval to implement a negative rate rider that will result in a further 1% reduction from the OEB-approved 2012 rates (EB-2011-0272), applied to the above-mentioned 2013 base distribution delivery rates, for NPDI customers (see **Section 2.0** below for further details). The cost of providing this rate rider will be obtained from the synergies that are generated from consolidating NPDI's operations into HONI.

The proposed transaction also protects HONI Distribution customers. HONI Distribution plans to file a five-year cost of service rate application in 2014 for rates effective 2015 to 2019 under the Board's Custom Incentive Regulation regime. That application will be based on HONI Distribution's existing customer base, i.e., it will not include any capital or OM&A costs associated with serving, maintaining or operating customers within the NPDI service territory. For reporting under the Board's Reporting and Record Keeping Requirements ("RRR") purposes, HONI Distribution will continue to report on its legacy business excluding NPDI and if applicable, any other future acquisitions. There will be no adverse impact on HONI Distribution's existing customers, operationally or through rate impacts. In the long term, because fixed costs of operations will be spread over a wider customer base, HONI Distribution's customers will see a small price benefit.

HOI has agreed to establish an Advisory Committee to provide a forum for communication between HOI and the county. The county may appoint three representatives to the committee, and HOI will include staff representation from the same geographic district as covered by NPDI's current distribution licence.

HOI has guaranteed a local presence within NPI's office on Victoria St. in the Town of Simcoe for a minimum of three years and will move its Dundas Field Business Centre functions from the City of Hamilton to the Town of Simcoe over a three-year period.

NPDI customers will benefit in the long term from access to the greater depth of expertise of HONI in the management and maintenance of the distribution system and in the economies of scale that HONI can realize due to its size.

HOI has committed to a capital expenditure budget and forecast in the Share Purchase Agreement that will allow it to maintain or improve reliability from the existing performance of NPDI.

NPDI customers will have access to the same level of customer service and billing systems that HONI Distribution's existing customers currently receive.

Upon approval, HONI Distribution will have accountability for planning for the entire c. Prior to the transaction, HONI Distribution served 14,000 customers within Norfolk County. After the transaction, HONI Distribution will serve all the customers of the county and will ensure that there is adequate supply for all of Norfolk County.

1.2 Promotion of Economic Efficiency and Cost Effectiveness

The completion of this transaction provides an example where significant operational savings can be achieved by combining an embedded LDC with HONI. HONI will leverage its existing back-office systems and processes (e.g. IT, accounting, and customer service) to obtain operational and capital synergies in serving the customers of NPDI. As HONI is facing significant demographic challenges and upcoming retirements, HONI will be able to provide job security for all NPDI staff, and will utilize both its existing staff and those acquired from NPDI to meet the needs of all its customers. As HONI Distribution will now be planning the electricity needs for the entire county, it will be able to more efficiently manage both the operating and capital costs associated with serving customers across the county. HONI Distribution's existing Simcoe Operating Centre is located less than 2 km from NPDI's Operating Centre located at 70 Victoria Street. HONI Distribution will consolidate operations between these two facilities over the next three years and transfer new work to the existing NPDI back-office and administrative staff, resulting in more efficient staff utilization. Upon closing of this transaction, NPDI staff will also be eligible to apply for vacancies within HONI, which will allow NPDI staff to fill vacancies across HONI Distribution in jobs that match their skill set and experience. HONI Distribution will gain operating and capital efficiencies while maintaining employment opportunities for all the acquired staff of NPDI.

1.3 Incremental Transaction Costs

Both parties to the transaction will have incurred some incremental costs associated with the transaction. These include costs incurred for due diligence, to negotiate and complete the transaction, costs associated with all necessary regulatory approvals, the integration costs to transfer the customers into HONI Distribution's customer and outage management systems, and initial costs to bring equipment up to HONI standards. These costs will be financed through productivity gains associated with the transaction and will not be included in HONI Distribution's revenue requirement and thus will not be funded by ratepayers

1.4 The "No Harm" Test

For the reasons addressed in the preceding sections, both NPDI and HONI submit that this transaction is consistent with the "no harm" test as outlined in the RP-2005-0018/EB-2005-0234/ EB-2005-0254/EB-2005-0257 Decision. The application lends itself to the objectives of the Board as set out in section 1 of the Act.

2.0 HYDRO ONE NP CUSTOMER RATES AND BILL IMPACT

As per the Share Purchase agreement, HONI Distribution proposes to include a rate rider to the 2013 OEB-approved rate schedule of NPDI's distribution delivery rates (effective May 1, 2013, EB-2012-0151) to give effect to a 1% reduction to the approved 2012 (EB-2011-0272) base delivery rates, then have such rates frozen and the rider applied for five years from the date of closing the proposed transaction.

HONI Distribution proposes that both Fixed and Volumetric rate riders be included in NPDI rate schedules for rates effective May 1, 2013 (as approved per their IRM application EB-2012-

0151). Detailed calculations of the rate riders can be found in **Exhibit A, Tab 2, Schedule, 1, Appendix A**.

HONI Distribution expects to realize operating synergies once it integrates the operations of NPDI into HONI. The net savings, after considering transaction and integration costs will more than offset the impact of offering a 1% reduction relative to 2012 base distribution delivery rates (as set out in EB-2011-0272) for five years. Examples of cost savings include reduced spending for vehicles, Information Systems (hardware and software), office equipment and furniture, SCADA, communications equipment, and reduced operating costs for central functions and services.

2.1 Bill Impact

Below are the impacts, for customers in the NPDI service territory, of the Proposed Transaction on the total bill as well as distribution base rates, in order to give effect to the proposed negative rate rider. The impacts are based on NPDI's approved rates effective May 1, 2013 applied to the average consumption levels for each rate class used by NPDI in calculating bill impacts as part of its 2013 IRM application, and assuming the proposed rate rider is approved. The rate reductions are slightly greater than 1%, given that 2013 approved rates are higher than 2012 approved rates:

	Change in Base Distribution Rates (%)	**Change in Total Bill (%)**
Residential	-1.41%	-0.42%
General Service less than 50 kW	-1.62%	-0.43%
General Service 50 to 4,999 kW	-1.45%	-0.18%
Unmetered Scattered Load	-1.33%	-0.37%
Sentinel Lighting	-1.42%	-0.74%
Street Lighting	-1.49%	-0.50%
Embedded Distributors	-1.47%	-5.45%

Detailed calculations of the bill impacts can be found in **Exhibit A, Tab 3, Schedule 1, Attachment 14.**

2.2 Rate Schedules

The approved current rate schedules for HONI Distribution, effective January 1, 2013 (EB-2012-0136) are attached as **Exhibit A, Tab 2, Schedule 1, Appendix B**. The approved rate schedules for NPDI effective May 1, 2012 (EB-2011-0272) are attached as **Exhibit A, Tab 2, Schedule 1, Appendix C**. The Board Decision (dated April 4, 2013) approving NPDI's 2013 rates, effective May 1, 2013 (EB-2012-0151) is attached as **Exhibit A, Tab 2, Schedule 1, Appendix D**. The proposed rate schedules, including the requested rate rider, for the area currently served by NPDI, effective after closing, are attached as **Exhibit A, Tab 2, Schedule 1, Appendix E.**

3.0 TIMING OF REBASING

3.1 Rate Rebasing

HONI Distribution proposes to defer the rate rebasing of the former NPDI (to be known as "HONI NP") to the earliest opportunity after 5 years from the date of closing the Proposed Transaction. This was an important factor in HONI Distribution's consideration of the merits of the Proposed Transaction. The deferral of rebasing HONI NP will give HONI Distribution time to retain savings to offset costs while protecting the interests of consumers across both existing service areas. This is consistent with the Board's policy determined in the Report of the Board titled, "Rate-making Associated with Distributor Consolidation".

At the end of the five-year rate freeze period in 2019, HONI Distribution expects to apply the Board's Incentive Regulation Mechanism to adjust HONI NP rates until the earliest opportunity to rebase their rates with HONI Distribution, currently expected in 2020.

3.2 Rate Harmonization

Similar to rebasing, HONI Distribution proposes to harmonize distribution rates at the earliest opportunity after the five-year rate freeze period. HONI Distribution's current expectation is that this will be in 2020. The rate harmonization process will be similar to the method adopted by HONI Distribution and approved by the Board in Application EB-2007-0681.

Until that time, HONI Distribution proposes to retain two separate rate schedules for customers in each of the service areas – that is those currently served by HONI Distribution and those currently served by NPDI.

4.0 REGULATORY ASSETS AND RATE RIDERS

NPDI currently has an approved Rate Rider for "Application of Tax Change", effective until April 30, 2014. The rider is for the sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board Approved base rates. Since there will be no rebasing of NPDI rates in the five-year rate freeze period, HONI Distribution proposes to continue to apply this rider until NPDI rates are rebased, and to true-up the balance at the next rate rebasing.

NPDI's current rate rider for the recovery of Lost Revenue Adjustment Mechanism ("LRAM") is effective until April 30, 2014. This rate rider will recover the lost revenue incurred in 2011 as a result of CDM programs implemented between 2005 and 2010, as well as the lost revenue from 2011 CDM activities between January 1, 2011 and December 31, 2011. HONI Distribution requests to continue to track variances in Board-approved versus actual revenue resulting from CDM initiatives from 2013 to the time of HONI NP rebasing, in the LRAM account.

5.0 USGAAP

HONI Transmission received OEB approval to utilize US Generally Accepted Accounting Principles ("US GAAP") as its approved framework for rate setting, regulatory accounting and regulatory reporting in the Decision with Reasons in EB-2011-0268 (issued on November 23, 2011). HONI Distribution also received OEB approval for the same in EB-2011-0399 (issued on March 23, 2012). The latter Decision noted "as the Board has found that Hydro One transmission rates should be set on the basis of USGAAP, it would generally be inefficient to require the distribution utility to use MIFRS for regulatory reporting and rate making".

NPDI's financial statements are currently prepared under Canadian Generally Accepted Accounting Principles ("CGAAP") and are compliant with the OEB letter (July 27, 2012) requiring all LDCs retaining CGAAP to adopt IFRS-compliant depreciation policy and an IFRS-compliant cost capitalization policy.

HONI requests approval to utilize USGAAP for accounting purposes in relation to HONI NP. Approval to use USGAAP for HONI NP will simplify the future rate integration to HONI Distribution; will avoid incremental costs or productivity losses by simplifying processes and avoiding the need for workarounds; and will facilitate HOI's consolidated reporting for securities filing purposes (possibly including future U.S. Securities and Exchange Commission), thus avoiding incremental costs and/or reduced productivity. It would be inefficient and costly to maintain different accounting regimes for divisions within HONI.

6.0 COMPLIANCE MATTERS

Pending approval of this transaction, the distribution business activities of NPDI, currently under Electricity Distribution Licence ED-2002-0521, will become subject to HONI's Electricity Distribution Licence ED-2003-0043, which licence will be amended for this purpose. The customers, assets, systems, processes and operations of NPDI will be fully integrated into HONI Distribution's business activities.

HONI confirms that it is materially in compliance with its regulatory requirements, subject to any approved regulatory exemptions. The list of specific code requirements from which HONI Distribution has been exempted can be found in Schedule 3 of HONI's Electricity Distribution Licence.

NPDI has confirmed that as of the date of the application, to the best of its knowledge, it is currently in compliance with all licence and code requirements per its Electricity Distribution licence (EB-2002-0521). It is expected that following the approval and completion of the transaction and after the integration of the NPDI distribution business activities into those of HONI, HONI Distribution will continue to be materially compliant with all applicable Legislation, Regulations, Market Rules, other Licence Conditions and Codes.

HONI's compliance policy will continue to require that confirmed instances of non-compliance be disclosed and mitigated as necessary including applications for exemptions from such requirements, if necessary. Any potential instances of non-compliance associated with NPDI's distribution business activities will be addressed during the integration process. For example, the non-electricity billing services currently being provided by NPDI will be transferred to Hydro One Telecom Inc. This transfer will be implemented after a short transition period in compliance with Section 71(1) of *Ontario Energy Board Act, 1998*. In any case, given the small customer base of NPDI (when compared to HONI Distribution), the integration is not expected to have any material impact on the current compliance status of HONI Distribution, even during the transition period.

7.0 SUMMARY

HOI requests a written hearing for this proceeding and submits that the evidence supports approval of the application for the following reasons:

- The application has no adverse impact on the price, adequacy, reliability and quality of service of NPDI or of HONI Distribution;
- The customers of both local distribution companies will be held harmless;
- This transaction was completed on a commercial basis between a willing seller and willing buyer. It is a demonstration of the type of benefits that can be realized from consolidation within the electric distribution sector in Ontario and is consistent with the findings of the Sector Review Panel. This transaction eliminates the duplication of effort between HONI and NPDI and results in a single electric distribution service provider for all of Norfolk County, which will ultimately lead to a lower cost of service across the HONI and NPDI service areas and will create downward pressure on electricity distribution rates.

APPENDIX A

Determination of Rate Riders per Acquisition Agreement

Rate Class	Distribution Charges	NPDI Distribution Rates Effective May 1, 2012	NPDI Distribution Rates After 1% Rate Reduction	NPDI Distribution Rates Effective May 1, 2013	Proposed Rate Riders per Acquisition Agreement
		A	B = A*0.99	C	D = B - C
Residential	Service Charge ($)	20.77	20.56	20.87	-0.31
	Distribution Volumetric Rate ($/kWh)	0.0217	0.0215	0.0218	-0.0003
	Low Voltage Volumetric Rate ($/kWh)	0.0009	0.0009	0.0009	0.0000
General Service < 50kW	Service Charge ($)	49.74	49.24	49.98	-0.74
	Distribution Volumetric Rate ($/kWh)	0.0155	0.0153	0.0156	-0.0003
	Low Voltage Volumetric Rate ($/kWh)	0.0008	0.0008	0.0008	0.0000
General Service 50 to 4,999 kW	Service Charge ($)	244.38	241.94	245.55	-3.61
	Distribution Volumetric Rate ($/kW)	3.9413	3.9019	3.9602	-0.0583
	Low Voltage Volumetric Rate ($/kW)	0.3050	0.3020	0.3050	-0.0030
Unmetered Scattered Load	Service Charge ($)	15.42	15.27	15.49	-0.22
	Distribution Volumetric Rate ($/kWh)	0.0087	0.0086	0.0087	-0.0001
	Low Voltage Volumetric Rate ($/kWh)	0.0008	0.0008	0.0008	0.0000
Sentinel Lighting	Service Charge ($)	6.50	6.44	6.53	-0.09
	Distribution Volumetric Rate ($/kW)	19.3402	19.1468	19.4330	-0.2862
	Low Voltage Volumetric Rate ($/kW)	0.2407	0.2383	0.2407	-0.0024
Street Lighting	Service Charge ($)	1.96	1.94	1.97	-0.03
	Distribution Volumetric Rate ($/kW)	7.3914	7.3175	7.4269	-0.1094
	Low Voltage Volumetric Rate ($/kW)	0.2358	0.2334	0.2358	-0.0024
Embedded Distributors	Service Charge ($)	613.91	607.77	616.86	-9.09
	Distribution Volumetric Rate ($/kWh)	N/A	N/A	N/A	N/A
	Low Voltage Volumetric Rate ($/kWh)	N/A	N/A	N/A	N/A

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

Ontario

EB-2012-0136

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

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2013.

BEFORE: Ken Quesnelle
Presiding Member

Cynthia Chaplin
Vice Chair and Member

RATE ORDER
December 20, 2012

Hydro One Networks Inc. (Hydro One) filed an application, dated June 15, 2012, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act,* 1998, c.15, Schedule B, and the Board's Incentive Regulation Mechanism (IRM) framework seeking approval for changes to the rates that Hydro One charges for electricity distribution, to be effective January 1, 2013. Hydro One has also applied for an adjustment to the rates it charges to accommodate proposed spending on projects contained in an Incremental Capital Module (ICM). The Board assigned the application File Number EB-2012-0136.

The Board issued a Notice of Application and Hearing dated July 6, 2012*.* On August 10, 2012 the Board issued Procedural Order No.1, approving a list of intervenors and intervenor eligibility for cost awards. Procedural Order No. 1 also included a timetable for hearing events and a draft Issues List. The Board made provision for submissions on the draft Issues List by Hydro One and intervenors.

Procedural Order No. 2 was issued on September 6, 2012 approving the Issues List and setting a number of steps in the hearing process, including interrogatories on Hydro One's evidence and intervenor evidence. Procedural Order No. 3 was issued on November 6, 2012 which included a ruling on confidentiality of certain Interrogatory responses and set dates for a Technical Conference, a Settlement Conference and for an oral hearing.

The Settlement Conference was held on November 30, 2012 and December 3, 2012. Hydro One filed a proposed Settlement Agreement on December 11, 2012. The proposed Settlement Agreement also included a Draft Rate Order.

In a Decision released on December 14, 2012, the Board approved the Settlement Agreement as filed. As the Draft Rate Order was filed with the Settlement Agreement, the Board provided for a short comment period. No party commented on or objected to, the Draft Rate Order or the related exhibits.

In the Decision, the Board also indicated that it would institute a written proceeding within this application, with regard to the issue of Payments In Lieu of Taxes (PILS) Account 1562. As these PILS amounts, if any, will be captured in a variance account, the resolution of this issue will not affect the rates approved for 2013. A procedural order will be issued shortly, establishing a structure for this hearing.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix A of this Rate Order is approved effective January 1, 2013 for electricity consumed or estimated to have been consumed on and after such date.

2. The Tariff of Rates and Charges set out in Appendix A of this Rate Order supersedes all previous Tariff of Rates and Charges approved by the Ontario Energy Board for Hydro One Networks Inc.'s Distribution service areas, and is final in all respects.

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

ISSUED at Toronto, December 20, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A

HYDRO ONE NETWORKS INC. DISTRIBUTION RATE ORDER TARIFF OF RATES AND CHARGES

EB-2012-0136

DECEMBER 20, 2012

HYDRO ONE NETWORKS INC.
TARIFF OF RATES AND CHARGES
FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

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

1.0 APPLICABILITY

These rates are applicable to Hydro One Networks' retail customers, who are supplied through Hydro One Networks' retail distribution system, including customers previously served by acquired distribution utilities.

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless

a) permitted by the Distributor's License or any Codes, or Orders of the Board, and amendments thereto as approved by the Board, or as specified herein, or

b) as identified in Hydro One Network's Distribution Customers Conditions of Service document, or
c) related to work or service of a customized nature and required for distribution assets, for example customer-requested pole relocation, repair of damages, new connections, etc.

This schedule does not contain any rates and charges relating to the electricity commodity (under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable) or any charges or assessments that are required by law to be charged by a distributor and are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment and any applicable taxes.

1.1 Implementation Dates

<u>Distribution Rates</u> – January 1, 2013 for all consumption or deemed consumption services used on or after that date.

<u>Miscellaneous Charges</u> – January 1, 2013 for all charges billed to customers on or after that date.

<u>Retail Transmission Rates</u> – January 1, 2013 for all consumption or deemed consumption services used on or after that date.

<u>Loss Factor Adjustment</u> – for all consumption or deemed consumption services billed following January 1, 2013 or later.

1.2 Customer Classifications

Residential - Year-round customer classification applies to a customer’s main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. All of the following criteria must be met:

1. Occupant represents and warrants to Hydro One Networks Inc, that for so long as he/she have year-round residential rate status for the identified dwelling he/she will not designate another property that he/she owns as a year-round residence for purposes of Hydro One rate classification

2. Occupier must live in this residence for at least four (4) days of the week for eight (8) months of the year and the Occupier must not reside anywhere else for more than three (3) days a week during eight (8) months of the year.

3. The address of this residence must appear on documents such as the occupant’s electric bill, driver’s licence, credit card invoice, property tax bill, etc.

4. 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 customer classification is defined as any residential service not meeting the Residential Year-round criteria. It includes dwellings such as cottages, chalets and camps.

General Service classification applies to any service that does not fit the description of residential classes. It includes combination type services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential
Farm classification is applicable to properties actively engaged in agricultural production as defined by Statistics Canada. It does not include tree, sod, or pet farms. Services to year round pumping stations or other ancillary services remote from the main farm shall be classed as farm.

Sub-Transmission (ST) classification refers to:

a) Embedded supply to Local Distribution Companies (LDCs), "Embedded" meaning receiving supply via Hydro One Distribution assets, and where Hydro One is the Host distributor to the Embedded LDC. Situations where the LDC is supplied via Specific Facilities are included.

   Or

b) load which:
   i) is three-phase; and
   ii) is directly connected to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive; the meaning of "directly" includes HON not owning the local transformation; and
   iii) is greater than 500 kW (monthly measured maximum demand averaged over the most recent calendar year or whose forecasted monthly average demand over twelve consecutive months is greater than 500 kW).

1.3 Density Zones

Urban Density Zone is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per kilometre.

Medium Density Zone is defined as areas containing 100 or more customers with a line density of at least 15 customers per kilometre.

Low Density Zone is defined as areas other than Urban or Medium Density Zone.

1.4 Rate Classes

Residential

- UR - Year-round Residence in an Urban High Density Zone
- R1 - Year-round Residence in a Medium Density Zone
- R2 - Year-round Residence in a Low Density Zone
- Seasonal - Seasonal Residential Occupancy

General Service

- UGe - General Service - Urban Density
  Applicable to Farm Three Phase customers, Farm Single Phase energy-billed customers, and Industrial Commercial customers located in an Urban Density Zone
- UGd - General Service - Urban Density
  Applicable to Farm Three Phase customers, Farm Single Phase demand-billed customers, and Industrial Commercial customers located in an Urban Density Zone
- GSe - General Service
  Single Phase and Three Phase Energy-billed customers not located in an Urban Density Zone
- GSd - General Service
  Single Phase and Three Phase Demand-billed customers not located in an Urban Density Zone
- DGen - Distributed Generation
  Embedded retail generation facility connected to the distribution system that is not classified as MicroFIT generation.
- MicroFIT - This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system
- Unmetered Scattered Load (GSe-Unmetered)
  This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that

can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.

Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Sub Transmission

- ST - Sub Transmission

  (Refer to criteria as specified in section 1.2)

Hydro One establishes billing determinants for demand customers at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a Customer's power factor is known to be less than 90 per cent, a kVA meter or other equivalent electronic meter shall be used for measuring and billing.

Lighting

- Street Lights

  This rate is applicable to all Hydro One Networks' core and acquired retail customers who have streetlights. Networks' core retail customers are customers of Networks' retail distribution system, excluding those customers previously served by acquired distribution utilities.

  Distribution Volumetric Energy Charge is on metered or estimated usage (per kWh)

  The energy consumption for street lights is estimated based on Networks' profile for street lighting load, which provides the amount of time each month that the street lights are operating.

- Sentinel Lights

  This rate is applicable to all Hydro One Networks' core and acquired retail customers who have separate service to a sentinel light. Networks' core retail customers are customers of Networks' retail distribution system, excluding those customers previously served by acquired distribution utilities.

The energy consumption for sentinel lights is estimated based on Networks' profile for sentinel lighting load, which provides the amount of time each month that the sentinel lights are operating.

Distribution Volumetric Energy Charge is on metered or estimated usage (per kWh)

1.5 Rural or Remote Electricity Rate Protection

Under the *Ontario Energy Board Act, 1998* and associated regulations, every qualifying year-round residence and farm with a principal residence is eligible to receive Rural or Remote Electricity Rate Protection (RRRP). The service charge shown for eligible R2 customers will be reduced by the applicable RRRP credit, which is currently $28.50 per month.

1.6 Specific Service Charges

Specific service charges details are included at the end of this schedule and are applicable to all customers.

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

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

Residential – Urban [UR]

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge (includes Smart Meter Funding Adder - $3.92)	$	16.50
Distribution Volumetric Rate	$ / kWh	0.02529
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00093)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kWh	0.00053
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.00044
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.00005)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00696
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00500

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

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Effective Date: January 1, 2013

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Residential – Medium Density [R1]

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge (includes Smart Meter Funding Adder - $3.92)	$	23.85
Distribution Volumetric Rate	$ / kWh	0.03353
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00090)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kWh	0.00062
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.00051
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.00005)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00707
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00509

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

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Residential – Low Density [R2]

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge* (includes Smart Meter Funding Adder - $3.92)	$	60.90
Distribution Volumetric Rate	$ / kWh	0.03683
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00085)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kWh	0.00091
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.00075
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.00008)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00690
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00480

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

* Under the Ontario Energy Board Act, 1998 and associated regulations, every qualifying year-round customer with a principal residence is eligible to receive Rural or Remote Rate Protection (RRRP). The service charge shown for eligible R2 customers will be reduced by the applicable RRRP credit, currently at $28.50.

HYDRO ONE NETWORKS INC.

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Seasonal Residential – Seasonal

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge (includes Smart Meter Funding Adder - $3.92)	$	23.42
Distribution Volumetric Rate	$ / kWh	0.08117
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00065)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kWh	0.00149
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.00123
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.00013)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00652
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00470

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

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General Service Energy Billed (less than to 50 kW) [GSe - metered]

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge (includes Smart Meter Funding Adder - $3.92)	$	39.79
Distribution Volumetric Rate	$ / kWh	0.03981
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00093)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kWh	0.00065
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.00054
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.00006)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00518
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00358

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

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Urban General Service Energy Billed (less than 50 kW) [UGe]

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge (includes Smart Meter Funding Adder - $3.92)	$	14.01
Distribution Volumetric Rate	$ / kWh	0.01666
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00106)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kWh	0.00031
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.00026
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.00003)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00535
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00366

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

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General Service Energy Billed (less than 50 kW) [GSe - Unmetered]

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge	$	29.37
Distribution Volumetric Rate	$ / kWh	0.03981
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00093)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kWh	0.00065
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.00054
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.00006)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00518
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00358

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

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General Service Demand Billed (50 kW and above) [GSd]

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge (includes Smart Meter Funding Adder - $3.92)	$	55.62
Distribution Volumetric Rate	$ / kW	11.370
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kW	(0.307)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kW	0.121
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kW	0.100
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kW	(0.010)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.68
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kW	1.14

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

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Urban General Service Demand Billed (50 kW and above) [UGd]

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge (includes Smart Meter Funding Adder - $3.92)	$	32.32
Distribution Volumetric Rate	$ / kW	6.914
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kW	(0.356)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kW	0.093
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kW	0.077
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kW	(0.008)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.75
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kW	1.19

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

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Distributed Generation [DGen]

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge (includes Smart Meter Funding Adder - $3.92)	$	41.64
Distribution Volumetric Rate	$ / kW	5.939
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kW	(0.048)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kW	0.071
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kW	0.059
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kW	(0.006)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	0.35
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kW	0.23

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

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Street Lights

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge	$	1.45
Distribution Volumetric Rate	$ / kWh	0.07209
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00102)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kWh	0.00059
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.00049
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.00005)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00435
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00303

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

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Sentinel Lights

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge	$	1.48
Distribution Volumetric Rate	$ / kWh	0.09877
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00100)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$ / kWh	0.00103
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.00085
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.00009)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00435
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00303

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

MicroFIT Generator

Service Charge	$	5.40

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Sub Transmission [ST]

Monthly Rates and Charges - Electricity Component

Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014) (14)	$ / kWh	(0.00050)

Monthly Rates and Charges - Delivery Component

Service Charge (includes Smart Meter Funding Adder - $3.92)	$	295.68
Meter Charge (for Hydro One ownership) (12)	$	471.17
Facility charge for connection to Common ST Lines (44 kV to 13.8 kV) (9)	$/kW (1) (15)	0.675
Facility charge for connection to Specific ST Lines (44 kV to 13.8 kV)	$/km (2)	640.12
Facility charge for connection to Specific Primary Lines (12.5 kV to 4.16 kV)	$/km (2)	496.09
Facility charge for connection to high-voltage (> 13.8 kV secondary) delivery High Voltage Dist'n Station	$/kW (1) (15)	1.614
Facility charge for connection to low-voltage (< 13.8 kV secondary) delivery High Voltage Dist'n Station	$/kW (1) (15)	3.579
Facility charge for connection to low voltage (< 13.8 kV secondary) Low Voltage Dist'n Station	$/kW (3) (15)	1.965
Volumetric Rate Rider #9A (General) - Deferral/Variance Account Disposition 2012 (expires December 31, 2014) (10)	$/kW (1) (15)	0.275
Volumetric Rate Rider #9B (Wholesale Market Service Rate) Deferral/Variance Account Disposition 2012 (expires December 31, 2014) (11)	$/kW (1) (15)	(0.627)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2014 or when new 2015 rates come into effect)	$/kW (1) (15)	0.010
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$/kW (1) (15)	0.008
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$/kW (1) (15)	(0.001)
Retail Transmission Service Rates (6)(7)(8):		
Retail Transmission Rate - Network Service Rate (4)	$/kW	3.18
Retail Transmission Rate - Line Connection Service Rate (5)	$/kW	0.70
Retail Transmission Rate - Transformation Connection Service Rate (5)	$/kW	1.63

Monthly Rates and Charges - Regulatory Component

Wholesale Market Service Rate (7) (13)	$/kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$/kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

Notes:

Note (1): The basis of the charge is the customer's monthly maximum demand. For a customer with multiple delivery points served from the same Transformer Station or High Voltage Distribution Station, the aggregated demand will be the applicable billing determinant. Demand is not aggregated between stations.

Note (2): The basis of the charge is kilometers of line, within the supplied LDC's service area, supplying solely that LDC.

Note (3): These rates are based on the "non-coincident demand" at each delivery point of the customer supplied by the station. This is measured as the kW demand at the delivery point at the time in the month of maximum load on the delivery point. For a customer connected through two or more distribution stations, the total charge for the connection to the shared distribution stations is the sum of the relevant charges for each of the distribution stations.

Note (4): The monthly billing determinant for the RTSR Network Service rate is:

- for energy-only metered customers: the customer's metered energy consumption adjusted by the total loss factor as approved by the Board.
- for interval-metered customers: the peak demand from 7 AM to 7 PM (local time) on IESO business days in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the Board.
- for non-interval-metered demand billed customers: the non-coincident peak demand in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the Board.

Note (5):

(a) The monthly billing determinant for the RTSR Line and Transformation Connection Service rates is

- for energy-only metered customers: the customer's metered energy consumption adjusted by the total loss factor as approved by the Board.
- for all demand billed customers: the non-coincident peak demand in the billing period. The rates shown are to be adjusted by the total loss factor as approved by the Board.

(b) For customers with load displacement generation above 1 MW, or 2 MW for renewable generation, installed after October 1998, RTSR connection is billed at the gross demand level.

Note (6): Delivery point with respect to RTSR is defined as the low side of the Transformer Station that steps down voltage from above 50 kV to below 50 kV. For a customer's multiple interval-metered delivery points served from the same Transformer Station, the aggregated demand at the said delivery points on the low side of the Transformer Station will be the applicable billing determinant.

Note (7): These rates pertain to the IESO's defined point of sale; consequently, appropriate loss factors as approved by the Board and set out in Hydro One Distribution's loss factors must be applied to the metered load of energy-metered customers. Similarly, appropriate loss factors as approved by the Board and set out as Hydro One Distribution's loss factors must be applied to the applicable tariffs of demand-billed customers.

Note (8): The loss factors, and which connection service rates are applied, are determined based on the point at which the distribution utility or customer is metered for its connection to Hydro One Distribution's system. Hydro One Distribution's connection agreements with these distribution utilities and customers will establish the appropriate loss factors and connection rates to apply from Hydro One Distribution's tariff schedules.

Note (9): The Common ST Lines rate also applies to the supply to Distributors which use lines in the 12.5 kV to 4.16 kV range from HVDSs or LVDSs.

Note (10): "Rider 9A (General)" is charged based on appropriate billing kW.

Note (11): "Rider 9B (Wholesale Market Service Charge)" applies to those customers who were charged Wholesale Market Service Charges by Hydro One Distribution.

Note (12): The Meter charge is applied to delivery points for which Hydro One owns the metering.

Note (13): The Wholesale Market Service Rate and the Rural or Remote Rate Protection Rate are charged solely to non-Wholesale-Market-Participants.

Note (14): The Global Adjustment rider applies to the non-LDC and non-RPP ST customers that were charged Wholesale Market Service Charges by Hydro One Distribution.

Note (15): For customers with load displacement generation above 1MW, or 2 MW for renewable generation, installed after October1998, the ST volumetric charges are billed at the gross demand level.

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers:
Primary Voltage under 50 kV (per kW)

Demand Billed	$ / kW	0.60
Energy Billed	cents / kWh	0.14

Transformer Loss Allowance

- Applicable to non-ST customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

  a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
  b) 1.0% for bank capacities over 400 kVA.
  And;

- Applicable to ST customers requiring a billing adjustment for transformer losses as the result of being metered on the secondary side of a transformer. The following uniform value shall be added to measured demand and energy (as metered on the secondary side) to adjust for transformer losses:

  a) 1.0%

- Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly.

- For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities.

Loss Factors

Rate Class	Factor
Residential	
UR	1.078
R1	1.085
R2	1.092
Seasonal	1.092
General Service	
GSe	1.092
GSd	1.061
UGe	1.092
UGd	1.061
DGen	1.061
Lights	
Street	1.092
Sentinel	1.092
Sub Transmission	
Distribution Loss Factors	
Embedded Delivery Points (metering at station)	1.000
Embedded Delivery Points (metering away from station)	1.028
Total Loss Factors	
Embedded Delivery Points (metering at station)	1.006
Embedded Delivery Points (metering away from station)	1.034

HYDRO ONE NETWORKS INC.
RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

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

SPECIFIC SERVICE CHARGES

Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	**Standard Formula**	**Other Formula**	**Time and Materials**
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge (Plus bank charges)	$15			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$562		
16	Service Layout Fee – Complex		$750		
17	Crossing Application – Pipeline		$2,600		
18	Crossing Application – Water		$2,960		
19	Crossing Application – Railroad		$3,100		
20	Line Staking – per meter		$3.75		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$935		
23	Conversion to Central Metering > 45 kW		$815		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$480		

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
26a	Connection Impact Assessment (CIA) Charges – Small & Medium		$10,335		
26b	Connection Impact Assessment (CIA) Charges – Large		$10,405		
27	Sentinel Lights Rental Rate per month			$7.10	
28	Sentinel Lights Pole Rental Rate per month			$4.15	
29	Joint Use for Cable and Telecom companies per pole			$22.35	
30	Joint Use for LDCs per pole			$28.61	

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

Ontario

EB-2011-0272

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

AND IN THE MATTER OF an application by Norfolk Power Distribution Inc. for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2012.

BEFORE: Karen Taylor
Presiding Member

Ken Quesnelle
Member

Revised RATE ORDER
May 24, 2012

Norfolk Power Distribution Inc. ("Norfolk Power") filed an application with the Ontario Energy Board (the "Board"), received on August 26, 2011 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Norfolk Power charges for electricity distribution, to be effective May 1, 2012. The Board assigned File Number EB-2011-0272 to the application.

The Board issued its rate order in this proceeding on April 4, 2012. Subsequently, Norfolk Power informed the Board that it had discovered two typographical errors in the Tariff of Rates and Charges issued with this order.

Specifically, the Rate Rider for Global Adjustment Sub-Account disposition was designated as a $/kW rate for both the GENERAL SERVICE 50 to 4,999 kW class and the SENTINEL LIGHTING class. This designation should have be $/kWh for both classes.

As a result, the Board has revised the Tariff of Rates and Charges for Norfolk Power.

THE BOARD ORDERS THAT:

1. The revised Tariff of Rates and Charges set out in Appendix A, is effective May, 1, 2012 and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2012.

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

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

DATED at Toronto, May 24, 2012

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

TO Revised RATE ORDER

Norfolk Power Distribution Inc.

EB-2011-0272

DATED: May 24, 2012

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	20.77
Rate Rider for Recovery of Residual Historical Smart Meter Costs – effective until April 30, 2016	$	0.10
Rate Rider for Recovery of Smart Meter Stranded Assets – effective until April 30, 2016	$	0.93
Distribution Volumetric Rate	$/kWh	0.0217
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0003
Rate Rider for Disposition of PILs Deferral/Variance Account (2012) – effective until April 30, 2013	$/kWh	0.0006
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.00004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0036

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	49.74
Rate Rider for Recovery of Residual Historical Smart Meter Costs – effective until April 30, 2016	$	3.42
Rate Rider for Recovery of Smart Meter Stranded Assets – effective until April 30, 2016	$	0.93
Distribution Volumetric Rate	$/kWh	0.0155
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0002)
Rate Rider for Disposition of PILs Deferral/Variance Account (2012) – effective until April 30, 2013	$/kWh	0.0004
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0031

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	244.38
Rate Rider for Recovery of Residual Historical Smart Meter Costs – effective until April 30, 2016	$	(1.03)
Rate Rider for Recovery of Smart Meter Stranded Assets – effective until April 30, 2016	$	0.93
Distribution Volumetric Rate	$/kW	3.9413
Low Voltage Service Rate	$/kW	0.3050
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.3243)
Rate Rider for Disposition of PILs Deferral/Variance Account (2012) – effective until April 30, 2013	$/kW	0.0627
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kW	0.0003
Retail Transmission Rate – Network Service Rate	$/kW	2.5546
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2460

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per Customer)	$	15.42
Distribution Volumetric Rate	$/kWh	0.0087
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0001)
Rate Rider for Disposition of PILs Deferral/Variance Account (2012) – effective until April 30, 2013	$/kWh	0.0005
Retail Transmission Rate – Network Service Rate	$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0031

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	6.50
Distribution Volumetric Rate	$/kW	19.3402
Low Voltage Service Rate	$/kW	0.2407
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	1.1141
Rate Rider for Disposition of PILs Deferral/Variance Account (2012) – effective until April 30, 2013	$/kW	0.6495
Retail Transmission Rate – Network Service Rate	$/kW	1.9364
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9833

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.96
Distribution Volumetric Rate	$/kW	7.3914
Low Voltage Service Rate	$/kW	0.2358
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	0.0688
Rate Rider for Disposition of PILs Deferral/Variance Account (2012) – effective until April 30, 2013	$/kW	0.2043
Retail Transmission Rate – Network Service Rate	$/kW	1.9267
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9632

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Board, and provided electricity by means of Norfolk Power Distribution Inc.'s distribution facilities. Further servicing details are available in the distributor's Conditions of Service

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	613.91
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0012)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0031

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

ALLOWANCES

Transformer Allowance for Ownership - General Service 50 to 4,999 kW customers - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling post-dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge / change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install / remove load control device – during regular hours	$	65.00
Install / remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Norfolk Power Distribution Inc.
Revised TARIFF OF RATES AND CHARGES
Effective Date May 1, 2012

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

EB-2011-0272

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0564
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0564
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0464
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0464

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

Ontario

EB-2012-0151

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

AND IN THE MATTER OF an application by Norfolk Power Distribution Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2013.

BEFORE: Marika Hare
Presiding Member

DECISION AND ORDER
April 4, 2013

Introduction

Norfolk Power Distribution Inc. ("NPDI"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on October 12, 2012 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that NPDI charges for electricity distribution, to be effective May 1, 2013.

NPDI is one of 77 electricity distributors in Ontario regulated by the Board. The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "IR Report"), issued on July 14, 2008, established a three year plan for 3rd generation incentive regulation mechanism ("IRM") (i.e., rebasing plus three years). In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the IRM plan until such time as the RRFE policy initiatives have been substantially completed.

In a letter dated October 18, 2012, the Board stated its expectation that the three rate setting methods set out in the *Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* would be available for the 2014 rate year.

As part of the plan, NPDI is one of the electricity distributors that will have its rates adjusted for 2013 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications. NPDI also sought approval for lost revenue adjustment mechanism ("LRAM") recovery and the removal of the retail transmission services rates from its Embedded Distributor rate class.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its IR Report, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008 (the "Supplemental Report"), and *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (collectively the "Reports"). Among other things, the Reports provide the relevant guidelines for 2013 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On June 28, 2012, the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the application filing requirements for IRM applications based on the policies in the Reports.

Notice of NPDI's rate application was given through newspaper publication in NPDI's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. No letters of comment were received. The Notice of Application indicated that intervenors could be eligible for cost awards with respect to NPDI's request for lost revenue adjustment mechanism ("LRAM") recoveries and a proposal to remove the retail transmission services rates from its Embedded Distributor rate class. The Vulnerable Energy Consumers Coalition ("VECC") applied and was granted intervenor status in this proceeding. The Board granted VECC eligibility for cost awards in regards to NPDI's request for LRAM recoveries and the removal of the retail transmission services rates from its Embedded Distributor class. Board staff also participated in the proceeding. The Board proceeded by way of a written hearing.

Written submissions from Board staff and VECC were due on January 14, 2013. Board staff filed its submissions by the deadline. Norfolk filed its reply on January 28, 2013. VECC filed its submissions on February 28, 2013. In its cover letter addressed to the Board, VECC noted that it had inadvertently missed the January 14 filing date and asked that the Board accept the submissions subject to the right of reply by Norfolk.

Norfolk consented to the filing and confirmed that it had no further submissions. It is unfortunate that VECC's submissions were late; however with no other intervenors participating in this proceeding, the Board finds the submissions of value. The Board therefore accepts the late filing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;
- Wholesale Market Service Rate;
- Smart Metering Entity Charge;
- MicroFIT Service Charge;
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances; and
- Review and Disposition of Lost Revenue Adjustment Mechanism.

Price Cap Index Adjustment

As outlined in the Reports, distribution rates under the IRM are to be adjusted by a price escalator, less a productivity factor of 0.72% and a stretch factor.

On March 21, 2013, the Board announced a price escalator of 1.60% for those distributors under IRM that have a rate year commencing May 1, 2013.

The stretch factors are assigned to distributors based on the results of two benchmarking evaluations to divide the Ontario industry into three efficiency cohorts. In its letter to Licensed Electricity Distributors dated November 28, 2012 the Board assigned NPDI to efficiency cohort 2, being the middle group, and a resulting cohort specific stretch factor of 0.4%.

The Board therefore has determined, on that basis, that the resulting price cap index adjustment is 0.48% (i.e. 1.60% - (0.72% + 0.40%)). The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across customer classes.

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

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charge; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection Charge

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Rural or Remote Electricity Rate Protection (“RRRP”) used by rate regulated distributors to bill their customers shall be $0.0012 per kilowatt hour effective May 1, 2013. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this RRRP charge.

Wholesale Market Service Rate

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service rate (“WMS rate”) used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this WMS rate.

Smart Metering Entity Charge

On March XX, 2013, the Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering Entity charge of $0.79 per month for Residential and General Service < 50kW customers for those distributors identified in the Board's annual *Yearbook of Electricity Distributors*. This charge will be in effect from May 1, 2013 to October 31, 2018. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this Smart Metering Entity charge.

MicroFIT Service Charge

On September 20, 2012, the Board issued a letter advising that the default province-wide fixed monthly charge for all electricity distributors related to the microFIT Generator Service Classification was to be updated to $5.40 per month effective with the implementation of electricity distributors' 2013 rates applications. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects the new default microFIT service charge.

Shared Tax Savings Adjustments

In its Supplemental Report*,* the Board determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate.

The calculated annual tax reduction will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers over a 12-month period, through a volumetric rate rider using annualized consumption by customer class underlying the Board-approved base rates.

NPDI's application originally included a tax sharing credit of $55,333. In response to Board staff interrogatory #1, NPDI corrected the regulatory taxable income used to calculate the savings, and updated this amount to a credit of $46,347.

The Board approves the disposition of the shared tax savings of $46,347 over a one year period (i.e. May 1, 2013 to April 30, 2014) and the associated rate riders for all customer rate classes.

Retail Transmission Service Rates ("RTSRs")

Electricity distributors are charged for transmission costs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

On June 22, 2012 the Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2013. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new Ontario Uniform Transmission Rates ("UTRs") levels and the revenues generated under existing RTSRs. Similarly, embedded distributors whose host is Hydro One Networks Inc. ("Hydro One") should adjust their RTSRs to reflect any changes in Hydro One's Sub-Transmission class RTSRs. The objective of resetting the rates is to minimize the prospective balances in Accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributors' specific RTSRs, Board staff provided a filing module.

Norfolk Power is a partially embedded distributor whose host is Hydro One.

On December 20, 2012 the Board issued its Rate Order for Hydro One Transmission (EB-2012-0031) which adjusted the UTRs effective January 1, 2013, as shown in the following table:

2013 Uniform Transmission Rates

Network Service Rate	$3.63 per kW
<u>Connection Service Rates</u>	
Line Connection Service Rate	$0.75 per kW
Transformation Connection Service Rate	$1.85 per kW

The Board also approved new rates for Hydro One Sub-Transmission class RTSRs effective January 1, 2013 (EB-2012-0136), as shown in the following table.

2013 Sub-Transmission RTSRs

Network Service Rate	$3.18 per kW
<u>Connection Service Rates</u> Line Connection Service Rate Transformation Connection Service Rate	 $0.70 per kW $1.63 per kW

The Board finds that these 2013 UTRs and Sub-Transmission class RTSRs are to be incorporated into the filing module.

NPDI requested the removal of the RTS rates for the Embedded Distributor class as they are no longer applicable. NPDI noted that the five customers within this class have five primary meter points (“PMEs”), each owned by Hydro One. NPDI stated that subsequent to the approval of its 2012 rates, Hydro One clarified that NPDI does not own the assets upstream of these PMEs, NPDI is not charged a transmission rate and therefore should not be charging Hydro One RTSRs.

In response to Board staff interrogatories, NPDI proposed to exclude the Embedded Distributor class from the disposition of account 1584 and 1586 and reallocated the total balance of these accounts to the other customers on the basis of kWh.

Board staff had no concerns with NPDI’s request to remove the RTSRs from the Embedded Distributor class as well as its proposal to deal with the disposition of accounts 1584 and 1586

The Board approves the removal of the RTS rates for the Embedded Distributor class and approves the disposition of accounts 1584 and 1586.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors’ Deferral and Variance Account Review Report Initiative* (the “EDDVAR Report”) provides that, during the IRM plan term, the distributor’s Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

NPDI's 2011 actual year-end total balance for Group 1 Accounts including interest projected to April 30, 2013 is a credit of $632,932. This amount results in a total credit claim of $0.0017 per kWh, which exceeds the preset disposition threshold. NPDI proposed to dispose of this credit amount over a one-year period.

In its submission, Board staff noted that the principal amounts to be disposed as of December 31, 2011 reconcile with the amounts reported as part of the *Reporting and Record-keeping Requirements* ("RRR"). Board staff submitted that the amounts should be disposed on a final basis. Board staff further submitted that NPDI's proposal for a one-year disposition period is in accordance with the EDDVAR Report.

The Board approves, on a final basis, the disposition of a credit balance of $632,932 as of December 31, 2011, including interest as of April 30, 2013 for Group 1 accounts. These balances are to be disposed over a one year period from May 1, 2013 to April 30, 2014.

The table below identifies the principal and interest amounts approved for disposition for Group 1 Accounts.

Account Name	**Account Number**	**Principal Balance A**	**Interest Balance B**	**Total Claim C = A + B**
LV Variance Account	1550	$23,766	$787	$24,553
RSVA - Wholesale Market Service Charge	1580	-$505,356	-$11,515	-$516,871
RSVA - Retail Transmission Network Charge	1584	-$125,853	-$5,485	-$131,338
RSVA - Retail Transmission Connection Charge	1586	-$407,047	-$8,890	-$415,937
RSVA - Power (excluding Global Adjustment)	1588	$700,513	$10,582	$711,095
RSVA - Power – Global Adjustment Sub-Account	1588	-$294,443	-$9,992	-$304,434
Total Group 1 Excluding Global Adjustment Sub-Account				
Total Group 1				**-$632,932**

For accounting and reporting purposes, the respective balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year. This entry should be completed on a timely basis to ensure that these adjustments are included in the reporting period ending June 30, 2013 (Quarter 2).

Review and Disposition of Lost Revenue Adjustment Mechanism ("LRAM")

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on April 26, 2012 outline the information that is required when filing an application for LRAM.

NPDI requested the recovery of an LRAM claim of $95,375. In response to interrogatories from Board staff NPDI confirmed that it had used Ontario Power Authority's ("OPA") 2011 final results. NPDI's LRAM claim consists of the lost revenues incurred in 2011 from CDM programs implemented between 2005 and 2010. NPDI proposed to recover the LRAM claim over a one-year period.

As well, NPDI requested the approval and recovery of historical Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) amounts related to lost revenue from 2011 CDM activities between January 1, 2011 and December 31, 2011. The requested LRAMVA claim is $15,691, including carrying charges of $439.

The Board's Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003, Page 13 states that at minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their Incentive Regulation Mechanism rate applications, if the balance is deemed significant by the applicant.

In response to VECC interrogatory 2(c), NPDI indicated that since a separate claim is being made for lost revenue of 2005 to 2010 CDM programs in 2011, it believes it is also appropriate to clear the LRAMVA account for 2011 energy savings related to CDM programs launched in 2011on a timely basis.

In its submission, VECC noted that the estimated reductions in demand related to 2011 programs have been incorporated into the load forecast for May 1, 2012 onward. Therefore, VECC agreed it is timely to dispose of the LRAMVA balance at this time even though the balance is not significant

The Board approves the disposition of the LRAMVA amounts related to programs implemented between 2005 and 2010. Although the LRAMVA claim for 2011 is insignificant, the Board agrees that given the new load forecast for May 1, 2012 onward it is reasonable to clear the balance at this time. The Board therefore approves a further disposition of $15,691 related to 2011 CDM programs.

Rate Model

With this Decision, the Board is providing NPDI with a rate model (spreadsheet) and applicable supporting models and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board has reviewed the entries in the rate model to ensure that they are in accordance with the 2012 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. NPDI’s new distribution rates shall be effective May 1, 2013.

2. NPDI shall review the draft Tariff of Rates and Charges set out in Appendix A. NPDI shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information within **7 days** of the date of issuance of this Decision and Order.

3. If the Board does not receive a submission from NPDI to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the draft Tariff of Rates and Charges set out in Appendix A of this Decision and Order will become final, effective May 1, 2013, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2013. NPDI shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

4. If the Board receives a submission from NPDI to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the Board will consider the submission of NPDI and will issue a final Tariff of Rates and Charges.

Cost Awards

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

1. VECC shall submit their cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. NPDI shall file with the Board and forward to the VECC any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and forward to NPDI any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

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

All filings to the Board must quote file number **EB-2012-0151,** be made through the Board's web portal at, https://www.pes.ontarioenergyboard.ca/eservice// and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, April 4, 2013
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

Draft Tariff of Rates and Charges

Board File No: EB-2012-0151

DATED: April 4, 2013

Norfolk Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0151

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accomodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex, or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any service work done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, an amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	20.87
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2016	$	0.10
Rate Rider for Recovery of Smart Meter Stranded Assets - effective until April 30, 2016	$	0.93
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0218
Low Voltage Volumetric Rate	$/kWh	0.0009
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0017)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) - effective until April 30, 2014	$/kWh	0.0004
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0032

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0151

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential acount taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kw. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	49.98
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2016	$	3.42
Rate Rider for Recovery of Smart Meter Stranded Assets - effective until April 30, 2016	$	0.93
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0156
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0017)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) - effective until April 30, 2014	$/kWh	0.0005
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0062
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0028

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0151

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	245.55
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2016	$	(1.03)
Rate Rider for Recovery of Stranded Assets - effective until April 30, 2016	$	0.93
Distribution Volumetric Rate	$/kW	3.9602
Low Voltage Service Rate	$/kW	0.3050
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kW	(0.3237)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.6615)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) - effective until April 30, 2014	$/kW	0.0262
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kW	0.0211
Retail Transmission Rate - Network Service Rate	$/kW	2.4951
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.1102

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0151

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	15.49
Distribution Volumetric Rate	$/kWh	0.0087
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0062
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0028

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0151

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	6.53
Distribution Volumetric Rate	$/kW	19.4330
Low Voltage Service Rate	$/kW	0.2407
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kW	(0.3438)
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kW	0.2079
Retail Transmission Rate - Network Service Rate	$/kW	1.8913
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.8762

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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

EB-2012-0151

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.97
Distribution Volumetric Rate	$/kW	7.4269
Low Voltage Service Rate	$/kW	0.2358
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kW	(0.3002)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	(0.6052)
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kW	0.0655
Retail Transmission Rate - Network Service Rate	$/kW	1.8818
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.8583

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0151

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Board, and provided electricity by means of Norfolk Power Distribution Inc.'s distribution facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	616.86
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0017)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0000
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0000

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Norfolk Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0151

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Norfolk Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0151

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Orderof the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges forthe Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00

Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

Norfolk Power Distribution Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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

EB-2012-0151

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0564
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0564
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0464
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0464

Hydro One Networks Inc. - Norfolk Power

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXXX, 2013

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

RESIDENTIAL SERVICE CLASSIFICATIONS

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex, or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit, and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	20.87
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2016	$	0.10
Rate Rider for Recovery of Smart Meter Stranded Assets - effective until April 30, 2016	$	0.93
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Rate Rider per Acquisition Agreement – effective until HONI’s next rebasing after 5-year rate freeze period	$	(0.31)
Distribution Volumetric Rate	$/kWh	0.0218
Rate Rider per Acquisition Agreement – effective until HONI’s next rebasing after 5-year rate freeze period	$/kWh	(0.0003)
Low Voltage Volumetric Rate	$/kWh	0.0009
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0017)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) – effective until April 30, 2014	$/kWh	0.0004
Rate Rider for Application of Tax Change – effective until HONI’s next rebasing after 5-year rate freeze period	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0032

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Networks Inc. - Norfolk Power

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXXX, 2013

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

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATIONS

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, an amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	49.98
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2016	$	3.42
Rate Rider for Recovery of Smart Meter Stranded Assets - effective until April 30, 2016	$	0.93
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	$	0.79
Rate Rider per Acquisition Agreement – effective until HONI’s next rebasing after 5-year rate freeze period	$	(0.74)
Distribution Volumetric Rate	$/kWh	0.0156
Rate Rider per Acquisition Agreement – effective until HONI’s next rebasing after 5-year rate freeze period	$/kWh	(0.0003)
Low Voltage Volumetric Rate	$/kWh	0.0008
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0017)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) – effective until April 30, 2014	$/kWh	0.0005
Rate Rider for Application of Tax Change – effective until HONI’s next rebasing after 5-year rate freeze period	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0062
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0028

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Networks Inc. - Norfolk Power

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXXX, 2013

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

GENERAL SERVICE 50 to 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	245.55
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2016	$	(1.03)
Rate Rider for Recovery of Stranded Assets - effective until April 30, 2016	$	0.93
Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$	(3.61)
Distribution Volumetric Rate	$/kW	3.9602
Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$/kW	(0.0583)
Low Voltage Volumetric Rate	$/kW	0.3050
Low Voltage Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$/kW	(0.0030)
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kW	(0.3237)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.6615)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) – effective until April 30, 2014	$/kW	0.0262
Rate Rider for Application of Tax Change – effective until HONI's next rebasing after 5-year rate freeze period	$/kW	0.0211
Retail Transmission Rate - Network Service Rate	$/kW	2.4951
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.1102

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Networks Inc. - Norfolk Power
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXXX, 2013

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, an amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit, and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	15.49
Rate Rider for per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$	(0.22)
Distribution Volumetric Rate	$/kWh	0.0087
Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$/kWh	(0.0001)
Low Voltage Volumetric Rate	$/kWh	0.0008
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Application of Tax Change – effective until HONI's next rebasing after 5-year rate freeze period	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0062
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0028

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Networks Inc. - Norfolk Power

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXXX, 2013

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

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, an amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit, and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	6.53
Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$	(0.09)
Distribution Volumetric Rate	$/kW	19.4330
Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$/kW	(0.2862)
Low Voltage Volumetric Rate	$/kW	0.2407
Low Voltage Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$/kW	(0.0024)
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kW	(0.3438)
Rate Rider for Application of Tax Change – effective until HONI's next rebasing after 5-year rate freeze period	$/kW	0.2079
Retail Transmission Rate - Network Service Rate	$/kW	1.8913
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.8762

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Networks Inc. - Norfolk Power
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXXX, 2013

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

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, an amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit, and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	1.97
Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$	(0.03)
Distribution Volumetric Rate	$/kW	7.4269
Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$/kW	(0.1094)
Low Voltage Volumetric Rate	$/kW	0.2358
Low Voltage Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$/kW	(0.0024)
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kW	(0.3002)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	(0.6052)
Rate Rider for Application of Tax Change – effective until HONI's next rebasing after 5-year rate freeze period	$/kW	0.0655
Retail Transmission Rate - Network Service Rate	$/kW	1.8818
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.8583

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Networks Inc. - Norfolk Power

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXXX, 2013

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

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Board, and provided electricity by means of Norfolk Power Distribution Inc.'s distribution facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, an amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit, and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	616.86
Rate Rider per Acquisition Agreement – effective until HONI's next rebasing after 5-year rate freeze period	$	(9.09)
Rate Rider for Disposition of Deferral/Variance Account (2013) - effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	(0.0017)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0000
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0000

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Networks Inc. - Norfolk Power
TARIFF OF RATES AND CHARGES
Effective and Implementation Date XXXX, 2013

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

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, an amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Hydro One Networks Inc. - Norfolk Power

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXXX, 2013

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

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect / Reconnect at meter - during regular hours	$	65.00
Disconnect / Reconnect at meter - after regular hours	$	185.00
Disconnect / Reconnect at pole - during regular hours	$	185.00
Disconnect / Reconnect at pole - after regular hours	$	415.00

Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

Hydro One Networks Inc. - Norfolk Power

TARIFF OF RATES AND CHARGES

Effective and Implementation Date XXXX, 2013

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

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, an amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit, and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0564
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0564
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0464
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0464

Ontario Energy Board

Application form for Applications under Section 86 of the *Ontario Energy Board Act, 1998*

PART I: GENERAL INFORMATION

1.1 Nature of Applications:

(A) under section 86(2)(b), the applicant is Hydro One Inc.("HOI") and the other party is The Corporation of the County of Norfolk (the "County"), regarding the acquisition by HOI of all of the shares of Norfolk Power Inc. ("NPI") of the parent company of the distributor Norfolk Power Distribution Inc.("NPDI"); and

(B) under section 86(1)(a) regarding the transfer, immediately ***following*** the transaction described in (A), of the assets and liabilities of the electricity distribution business from NPDI (applicant) to Hydro One Networks Inc. (other party). If these applications are approved, the distribution system assets of NPDI will move from control by the County to direct ownership by HONI.

1.1.1 Application Type

☒ For leave for a transmitter or distributor to sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety (section 86(1)(a))

☐ For leave for a transmitter or distributor to sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public (section 86(1)(b))

☐ For leave for a transmitter or distributor to amalgamate with any other corporation (section 86(1)(c))

☐ For leave for a person to acquire voting securities that will exceed 20% of a distributor or transmitter (section 86(2)(a))

☒ For leave for a person to acquire control of a company that holds more than 20% of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of the corporation (section 86(2)(b))

1.1.2 Notice under section 80 or 81 of the Act

Is a notice of proposal required under section 80 or 81 of the Act?

☐ Yes

☒ No

If yes, the applicant must also file a completed "Preliminary Filing Requirements for a Notice of Proposal Under Sections 80 and 81 of the *Ontario Energy Board Act, 1998*" with the Board.

1.2 <u>Identification of the Parties</u>

1.2.1 <u>Name of Applicant</u>

Legal name of the applicant: Hydro One Inc.

Name of Primary Contact:

Mr. ☒ Miss ☐ Other ☐ Mrs. ☐ Ms. ☐	
Last Name	Engelberg
First Name	Michael
Initial	
Title/Position	Assistant General Counsel

Address of Head Office: 483 Bay Street

City	Province/State	Country	Postal/Zip Code
Toronto	Ontario	Canada	M5G 2P5

Phone Number	Fax Number	E-mail Address
(416) 345-6305	(416) 345-6972	mengelberg@HydroOne.com

Legal name of the applicant in (B): Norfolk Power Distribution Inc.

The transaction which is the subject of the application by NPDI under s. 86(1) occurs following the acquisition of NPDI's parent by HOI and is contingent on approval of the application by Hydro One Inc. under s.86(2). The address given for the applicant NPDI below, is the address of Hydro One Networks Inc. to which all notices should be directed for NPDI <u>as applicant.</u> However, NPDI, the currently licenced distributor is represented by J. Mark Rodger of the law firm of Borden Ladner Gervais and he should be considered the <u>primary contact for NPDI</u> with respect to the application under s. 86(2). With respect to the s.86(1) application, the primary contact named below is an employee of NPDI and is available at the phone and fax numbers indicated.

Name of Primary Contact:

Mr. ☒ Miss ☐ Other ☐ Mrs. ☐ Ms. ☐	
Last Name	McEachran
First Name	Jody
Initial	
Title/Position	Acting Chief Executive Officer

Address of Head Office: 483 Bay Street

City	Province/State	Country	Postal/Zip Code
Toronto	Ontario	Canada	M5G 2P5

Phone Number	Fax Number	E-mail Address
(519) 426-4440 X 2264	(519) 426-4514	jmceachran@norfolkpower.on.ca

Address of Primary Contact for NPDI in relation to s. 86(1) application: Borden Ladner Gervais LLP,Scotia Plaza, 40 King St. W.

Mr. ☒ Mrs. ☐
Miss ☐ Ms. ☐
Other ☐ ______________

Last Name	First Name	Initial
Rodger	Mark	

Title/Position: Counsel

City	Province/State	Country	Postal/Zip Code
Toronto	Ontario	Canada	M5H 3Y4

Phone Number	Fax Number	E-mail Address
(416) 367-6190	(416) 361-7088	mrodger@blg.com

Other Party to the Transaction (if more than one attach a list)
Name of the other party: The Corporation of Norfolk County

Name of Primary Contact:

Mr. ☒ Mrs. ☐
Miss ☐ Ms. ☐
Other ☐ ______________

Last Name	First Name	Initial
Travale	Dennis	

Title/Position: Mayor

Address of Head Office: 50 Colborne Street South

City	Province/State	Country	Postal/Zip Code
Simcoe	Ontario	Canada	N3Y 4N5

Phone Number	Fax Number	E-mail Address
(519) 426-5870 x1220	(519) 426-8573	Dennis.Travale@norfolkcounty.ca

Name of the other party: Hydro One Networks Inc.

Name of Primary Contact:

Mr. ☒	Mrs. ☐	Last Name	First Name	Initial
Miss ☐	Ms. ☐	Waller	Jamie	
Other ☐				
		Title/Position		
		Sr. Regulatory Coordinator		

Address of Head Office: 483 Bay Street

City	Province/State	Country	Postal/Zip Code
Toronto	Ontario	Canada	M5G 2P5
Phone Number	Fax Number	E-mail Address	
(416) 345-6948	(416) 345-5866	regulatory@HydroOne.com	

1.3 Description of the Business of Each of the Parties

1.3.1 Please provide a description of the business of each of the parties to the proposed transaction, including each of their affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity ("Electricity Sector Affiliates").

Norfolk Power Distribution Inc. ("NPDI")

NPDI owns and is responsible for the operation, maintenance and management of the assets associated with the distribution of electrical power and energy within its service territory, as specified in Distribution Licence ED-2002-0521 (a copy of which is provided in **Exhibit A, Tab 3, Schedule 1 Attachment 1**). NPDI also provides water and waste water billing and metering services to Norfolk County.

NPDI is, at the date of this application, a wholly-owned subsidiary of Norfolk Power Inc. ("NPI"), a holding company, itself wholly-owned by Norfolk County.

Hydro One Inc. ("HOI")

Hydro One Inc. is wholly-owned by the Province of Ontario and is the parent company of Hydro One Networks Inc., Hydro One Brampton Networks Inc., Hydro One Remote Communities Inc. and Hydro One Telecom Inc.

Hydro One Networks Inc. ("HONI")

Hydro One Networks Inc. is a wholly-owned subsidiary of HOI and is the largest transmitter and distributor of electricity in Ontario. HONI's distribution company serves approximately 1.2 million customers. Customers include local distribution companies, customers with load exceeding 5 MW, and rural and urban customers. Distribution assets as at December 31, 2012, had a net book value of \$5.3 billion. HONI Distribution owns and is responsible for the operation, maintenance and management of the assets associated with the distribution of electrical power and energy within its service territory, as specified in Distribution Licence ED-2003-0043 (a copy of which is provided in **Exhibit A, Tab 3, Schedule 1, Attachment 2**). HONI also has a regulated transmission business owning 97% of transmission in Ontario with almost 30,000 km of high-voltage transmission lines.

Hydro One Brampton Networks Inc.
Hydro One Brampton Networks Inc. is HOI's urban distribution company serving customers in the GTA.

Hydro One Remote Communities Inc.
Hydro One Remote Communities Inc. operates a small, regulated generation and distribution system serving remote communities across Northern Ontario that are not connected to Ontario's electricity grid.

HOI's other business segment is represented primarily by the operations of **Hydro One Telecom Inc. ("HOT")**. This subsidiary markets dark and lit fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. The assets of this segment constituted approximately \$600 million of HOI's total assets of \$21 billion as at December 31, 2012.

Norfolk Energy Inc. ("NEI"), a provider of dark fibre telecommunications services, has assets that will be subsumed within HOT. While this affiliate transaction does not require OEB approval under the MAAD requirements, information related to it is provided in order to present a complete picture of the entire transaction through the sale-purchase of NPI shares by HOI.

1.3.2 Please provide a description of the geographic territory served by each of the parties to the proposed transaction, including each of their Electricity Sector Affiliates, if applicable.

Norfolk Power Distribution Inc.

As defined in Schedule 1 to its Distribution Licence, NPDI serves the geographical territory described as follows (the "NPDI Service Territory"):

(a) the westerly half of the former City of Nanticoke within the Municipality of the Town of Norfolk as of December 31, 2000;

(b) the former Town of Delhi (in the former Township of Delhi) within the Municipality of the Town of Norfolk as of December 31, 2000;

(c) the former Town of Port Rowan (in the former Township of Norfolk) within the Municipality of the Town of Norfolk as of December 31, 2000; and Villages of Long Point Bay, Phase 7, Registered Plan #37M-23, Block 36 & Block 37, Lot #3 to 14 and Lot #17 to 35;

(d) the former Town of Simcoe within the Municipality of the Town of Norfolk as of December 31, 2000; and

(e) the rural area of Norfolk County, east of Highway 24.

Hydro One Networks Inc.

See HONI's Electricity Distribution Licence ED-2003-0043 (**Exhibit A, Tab 3, Schedule 1 Attachment 2**), Schedule 1 for a Definition of its Distribution Service Area.

The attached map **(Exhibit A, Tab 3, Schedule 1**, **Attachment 3)** is a representation of Hydro One Distribution's service territory. It is not a substitute for the written description in its Electricity Distribution Licence ED-2003-0043. The map is accurate where local distribution company's ("LDC") boundaries conform to existing or former municipal boundaries but is only a best-effort representation in locations where there have been annexations or for other reasons the LDC boundaries are different from current or former municipal boundaries.

1.3.3 Please provide a description of the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.

Norfolk Power Distribution Inc.

NPDI's distribution system serves approximately 19,000 Residential and General Service customers in the NPDI Service Territory.

The following table provides a summary of the number of customers and connections by customer class for 2011:

Rate Class	Number of Customers
Residential	16,880
General Service < 50 kW	1,984
General Service 50 to 4,999 kW	167
Embedded Distributor	5
Street Lighting	3,819
Sentinel Lighting	372
Unmetered Scattered Load	76
Total	**23,303**

Hydro One Networks Inc. - Distribution

HONI's distribution system serves approximately 1.2 million customers in its Service Territory.

The following table provides a summary of the number of customers in each rate of the above rate classes as filed in Hydro One Networks Inc. Distribution's ("HONI Distribution") most recent rebasing application:

Rate Class	Number of Customers
Urban Density Residential (UR)	140,540
Medium Density Residential (R1)	412,455
Low Density Residential (R2)	367,107
Seasonal Residential	156,901
General Service Energy Billed (GSe)	98,776
General Service Demand Billed (GSd)	7,361
Urban Density General Service Energy (UGe)	10,577
Urban Density General Service Demand (UGd)	1,130
Street Lights	5,234
Sentinel Lights	37,506
Distributed Generation (DGen)	88
Sub Transmission (ST)	607
Total	**1,238,282**

1.3.4 Please provide a description of the proposed geographic service area of each of the parties after completion of the proposed transaction.

> HONI's geographic service area will be amended to include all of the municipality of The Corporation of Norfolk County, which includes the former Town of Delhi, the westerly half of the former City of Nanticoke, the former Village of Port Rowan (and Villages of Long Point Bay) and the former Town of Simcoe. The licence and geographic service area for NPDI will be cancelled.

1.3.5 Please attach a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.

> Please refer to **Exhibit A, Tab 3, Schedule 1, Attachments 4 and 5** for corporate charts of HOI and the County, respectively.

1.4 Description of the Proposed Transaction

1.4.1 Please provide a detailed description of the proposed transaction.

> On April 2, 2013, the County (as Vendor) and HOI (as Purchaser) entered into a share purchase agreement (the "Agreement"), whereby the Vendor agreed to sell, and the Purchaser agreed to purchase, all of the issued and outstanding shares of NPI (the "Shares"). The purchase price is $93 million, comprising a cash payment of approximately $66 million for the Shares and the assumption of NPI's long-term debt of approximately $27 million. The Agreement contemplates the transaction closing 30 days following the Parties' receipt of all Required Approvals, including Ontario Energy Board ("the Board" or "OEB") approval of this application under sections 86(2) and 86(1) of the *Ontario Energy Board Act, 1998*.
>
> A copy of the signed Agreement is attached hereto as **Exhibit A, Tab 3, Schedule 1, Attachment 6**. The Agreement contemplates the following items in addition to the sale of the Shares:
>
> (a) The purchase price is subject to adjustment within 90 days following closing, for Working Capital, Net Fixed Assets, and Long-Term Debt, as defined in the Agreement;
>
> (b) Along with this Application, HONI will apply to the OEB for approval to include a negative rate rider to NPDI's electricity rates (effective May 1, 2013) to reduce base delivery distribution rates by one per cent (1%) of the EB-2011-0272 approved 2012 rates, and to have such rates apply for the next five years (please refer to **Exhibit A, Tab 2, Schedule 1, Section 2.0** of this application for further details);
>
> (c) HOI or an affiliate shall offer all employees of NPI and NPDI continued employment; and
>
> (d) HOI and the county shall establish an advisory committee which shall include at least three representatives from the county, to monitor and provide input with respect to the provision of distribution services in Norfolk County.
>
> Immediately upon acquiring the shares of NPI, NPDI's distribution assets and liabilities will be transferred to HONI. The book value of the assets that will be transferred to HONI Distribution's rate base is approximately $53.9 million.

1.4.2 Please provide the details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.

> As described in section 1.4.1, the total purchase price is $93 million, comprising a cash payment of approximately $66 million for the Shares plus the assumption of NPI's long-term debt of approximately $27 million. The Agreement contemplates three types of adjustments to purchase price: (i) Working Capital, (ii) Net Fixed Assets, and (iii) Long Term Debt, as defined in the Agreement. These adjustments will be calculated within 90 days following closing.

1.4.3 Please attach the financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.

> Please refer to the following attachments to **Exhibit A, Tab 3, Schedule 1** for a copy of the audited financial statements for the past two (2) most recent years:
>
> - **Attachment 7** 2012 Hydro One Inc. Consolidated
> - **Attachment 8** 2011 Hydro One Inc. Consolidated
> - **Attachment 9** 2012 Hydro One Networks Inc. - Distribution
> - **Attachment 10** 2011 Hydro One Networks Inc. - Distribution
> - **Attachment 11** 2012 Norfolk Power Distribution Inc.
> - **Attachment 12** 2011 Norfolk Power Distribution Inc.
>
> Note that although The Corporation of Norfolk County is a party to this transaction, its financial statements have not been included, as they are not relevant to the transaction.

1.4.4 Please attach the pro forma financial statements for each of the parties (or if amalgamation, the one party) for the first full year following the completion of the proposed transaction.

> The proposed transaction will not have a material impact on HONI Distribution's financial position. The price is less than 2% of HONI Distribution's net fixed assets.

1.5 Documentation

1.5.1 Please provide copies of all annual reports, proxy circulars, prospectuses or other information filed with securities commissions or similar authorities or sent to shareholders for each of the parties to the proposed transaction and their affiliates within the past 2 years.

> HOI
>
> Information which HOI has filed to the Ontario Securities Commission is publicly available through SEDAR (www.sedar.com).
>
> NPDI
>
> This corporation does not file any material with securities commissions.

1.5.2 Please list all legal documents (including those currently in draft form if not yet executed) to be used to implement the proposed transaction.

> A copy of the Share Purchase Agreement is provided in **Exhibit A, Tab 3, Schedule 1, Attachment 6**. Please note that the Agreement has been redacted to remove any "personal information" within the

meaning of the *Freedom of Information and Protection of Privacy Act* (Ontario) and pursuant to section 42 of that Act such information should not be released publicly.

A pro forma Asset Transfer Agreement will be used to transfer the assets and liabilities of the NPDI distribution business to HONI.

A copy of the resolution of the County dated April 2, 2013 authorizing the sale of shares to Hydro One Inc. is provided as **Exhibit A, Tab 3, Schedule 1, Attachment 13**.

1.5.3 Please list all Board issued licences held by the parties and confirm that the parties will be in compliance with all licence, code and rule requirements both before and after the proposed transaction. If any of the parties will not be in compliance with all applicable licences, codes and rules after completion of the proposed transaction, please explain the reasons for such non-compliance. (Note: any application for an exemption from a provision of a rule or code is subject to a separate application process.)

Pending approval of this transaction, the distribution business activities of NPDI, currently under Electricity Distribution Licence ED-2002-0521, will become subject to HONI's Electricity Distribution Licence ED-2003-0043, which licence will be amended for this purpose. The customers, assets, systems, processes and operations of NPDI will be fully integrated into HONI Distribution's business activities.

HONI confirms that it is materially in compliance with its regulatory requirements, subject to any approved regulatory exemptions. The list of specific code requirements from which HONI Distribution has been exempted can be found in Schedule 3 of HONI's Electricity Distribution Licence.

NPDI has confirmed that as of the date of the application, to the best of its knowledge, it is currently in compliance with all licence and code requirements per its Electricity Distribution licence (EB-2002-0521). It is expected that following the approval and completion of the transaction and after the integration of the NPDI distribution business activities into those of HONI, HONI Distribution will continue to be materially compliant with all applicable Legislation, Regulations, Market Rules, other Licence Conditions and Codes.

HONI Distribution's compliance policy will continue to require that confirmed instances of non-compliance be disclosed and mitigated as necessary including applications for exemptions from such requirements, if necessary. Any potential instances of non-compliance associated with NPDI's distribution business activities will be addressed during the integration process. For example, the non-electricity billing services currently being provided by NPDI will be transferred to Hydro One Telecom Inc. This transfer will be implemented after a short transition period in compliance with Section 71(1) of *Ontario Energy Board Act, 1998*. In any case, given the small customer base of NPDI (when compared to HONI Distribution), the integration is not expected to have any material impact on the current compliance status of HONI Distribution, even during the transition period.

1.6 <u>Consumer Protection</u>

1.6.1 Please explain whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.

As mentioned above, NPI is a holding company, which is wholly-owned by the County. NPI in turn wholly owns NPDI, a licenced electricity distributor. The purchase of the shares by HOI from the

County (as described in section 1.4.1 and the Agreement) will therefore result in a change of control of NPI, and as a result, of NPDI.

1.6.2 Please indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.

As discussed in section 1.4.1, as a result of the proposed transaction, HONI Distribution is applying to the Board for approval to include a negative rate rider to NPDI's approved 2013 rates to give effect to a 1% reduction to 2012 base electricity distribution delivery rates (exclusive of rate riders) (EB-2011-0272)(see **Exhibit A, Tab 2, Schedule 1, Section 2.0**).

The existing customers of HONI Distribution will also be held harmless from this transaction. HONI Distribution will apply for 2015-2019 rates under the Custom Incentive Ratemaking regime. That application will be based on HONI Distribution's existing customer base, i.e., it will not include any capital or OM&A costs associated with serving, maintaining or operating customers within the NPDI service territory. For reporting under the Board's Reporting and Record Keeping Requirements ("RRR") purposes, HONI Distribution will continue to report on its legacy business excluding NPDI and any other future acquisitions. There will be no adverse impact on HONI Distribution existing customers, operationally or through rate impacts. In the long term, because fixed costs of operations will be spread over a wider customer base, HONI Distribution customers will see a small price benefit.

HOI has agreed to establish an Advisory Committee to provide a forum of communication between HOI and the county. The county may appoint three representatives to the committee, and HOI will include staff representation from the same geographic district as covered by NPDI's distribution licence.

Customers of NPDI will benefit in the long term from access to the greater depth of expertise of HONI in the management and maintenance of the distribution system and in the economies of scale that HONI can realize due to its size.

HOI has committed to a capital expenditure budget and forecast in the Share Purchase Agreement that will allow it to maintain or improve reliability from the existing performance of NPDI.

The customers of NPDI will have access to the same level of customer service and billing systems that HONI Distribution's existing customers currently receive.

1.6.3 Please describe the steps, including details of any capital expenditure plans that will be taken to ensure that operational safety and system integrity are maintained after completion of the proposed transaction.

Through the share acquisition described herein, the acquired NPDI assets will be fully integrated with HONI Distribution's assets to ensure the safe and secure operations and system integrity for both the acquired customers and the neighbouring HONI Distribution customers. The assets will be maintained and operated by HONI Distribution in the same fashion and to the same standards as HONI Distribution's current assets. The acquisition will not adversely affect operational safety or system integrity.

In addition, Section 6.6 of the Share Purchase Agreement outlines an agreed capital expenditure budget and forecast for NPDI for 2013 to 2017.

1.6.4 Please provide details, including any capital expenditure plans, of how quality and reliability of service will be maintained after completion of the proposed transaction. Indicate where service centres will be located and expected response times.

In performing maintenance on the acquired NPDI distribution system, HONI's distribution system standards will be used. HONI Distribution will thereby be able to serve the customers of NPDI with the same level of service HONI Distribution provides its existing customers by virtue of the existing customer service practices and policies of HONI.

Electric utility service to customers currently served by NPDI will remain subject to OEB rules and regulations governing all Ontario distributors.

Reliability will be maintained from the use of existing and required resources and as a result response times are not expected to be affected.

1.6.5 Please indicate whether the parties to the proposed transaction intend to undertake a rate harmonization process after the proposed transaction is completed. If yes, please provide a description of the plan.

HONI Distribution proposes to harmonize distribution rates at the earliest opportunity after the five-year rate freeze period. HONI Distribution's current expectation is that this will be in 2020. The rate harmonization process will be similar to the method adopted by HONI and approved by the Board in Application EB-2007-0681.

Until that time, HONI proposes to retain two separate distribution rate schedules for customers in each of the service areas – i.e. those currently served by Hydro One Distribution and those currently served by NPDI. Please see **Exhibit A, Tab 2, Schedule 1, Sections 2.0 and 3.0** for further details on rates.

1.6.6 If the application is for an amalgamation, please provide a proposal for the time of rebasing the consolidated entity in accordance with the five-year limit set by the Board.

The proposed transaction does not contemplate an amalgamation.

For details on HONI's rebasing strategy, please see **Exhibit A, Tab 2, Schedule 1, Section 3.0.**

1.6.7 Please identify all incremental costs that the parties to the proposed transaction expect to incur. These may include incremental transaction costs, (i.e., legal), incremental merged costs (i.e., employee severances), and incremental ongoing costs (i.e., purchase and maintenance of new IT systems). Please explain how the new utility plans to finance these costs.

The transaction will not result in a new utility.

Incremental costs associated with the transaction include costs incurred for due diligence, to negotiate and complete the transaction, costs associated with all necessary regulatory approvals, the integration costs to transfer the customers into HONI's customer and outage management systems, plus initial costs to bring equipment up to HONI's standards. These costs will be financed through productivity gains associated with the transaction and will not be included in HONI's revenue requirement and thus will not be funded by ratepayers**.**

1.6.8 Please describe the changes, if any, in distribution or transmission rate levels (as applicable) and the impact on the total bill that may result from the proposed transaction.

Below are the impacts of the Proposed Transaction on the total bill, as well as the distribution portion of the total bill, based on NPDI's approved rates effective May 1, 2013, applied to the average consumption levels for each rate class used by NPDI in calculating bill impacts as part of its 2013 IRM application, and assuming the proposed rate rider to give effect to the reduction is approved. The rate reductions are slightly greater than 1% given that 2013 approved rates are higher than 2012 approved rates.

	Change in Base Distribution Rates (%)	**Change in Total Bill (%)**
Residential	-1.41%	-0.42%
General Service less than 50 kW	-1.62%	-0.43%
General Service 50 to 4,999 kW	-1.45%	-0.18%
Unmetered Scattered Load	-1.33%	-0.37%
Sentinel Lighting	-1.42%	-0.74%
Street Lighting	-1.49%	-0.50%
Embedded Distributors	-1.47%	-5.45%

Detailed calculations of the bill impacts can be found in **Exhibit A, Tab 3, Schedule 1, Attachment 14.**

HONI is requesting to continue NPDI's Rate Rider for "Application of Tax Change" until NPDI's rates are rebased in 2020. Please see **Exhibit A, Tab 2, Schedule 1, Section 4.0** for further details.

1.6.9 Please provide details of the costs and benefits of the proposed transaction to the customers of the parties to the proposed transaction.

NPDI's distribution customers will experience no harm from this transaction. There will be no additional costs to the customers of the parties to the proposed transaction. To the contrary, and as stated in Section 1.6.2, they will have the benefit of the negative rate rider requested in this Application and have their rates frozen at that reduced level for the next five years. NPDI's customers will further benefit from HONI's 24-hour outage response process, Conservation and Demand Management programs, Mobile Outage application, 24-hour web access to their accounts, and an option to be e-billed via the internet.

HONI's current customers will continue to enjoy the same service they receive now, and the added benefit resulting from the spreading of fixed costs over a larger customer base when NPDI is added to HONI's rate base, expected in 2020.

1.7 Economic Efficiency

1.7.1 Please indicate the impact the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity). Details on the impacts of the proposed transaction on economic efficiency and cost effectiveness should include, but are not limited to, impacts on administration support functions such as IT, accounting, and customer service.

HONI will leverage its existing back-office systems and processes (e.g. IT, accounting, and customer service) to obtain operational and capital synergies in serving the customers of NPDI. As HONI is facing significant demographic challenges and upcoming retirements, HONI will be able to provide job security for all NPDI staff and will utilize both its existing staff and those acquired from NPDI to meet the needs of all its customers. As HONI Distribution will now be planning the electricity needs for all of Norfolk County, it will be able to more efficiently deliver both the operating and capital costs associated with serving the customers across the entire county. HONI Distribution will also look to optimize the use of its existing Simcoe Operating Centre and the NPDI Operating Centre.

1.8 Financial Viability

1.8.1 Please provide a valuation of any assets or shares that will be transferred in the proposed transaction. Provide details on how this value was determined, including any assumptions made about future rate levels.

HOI and the County have entered into a Share Purchase Agreement whereby HOI will be purchasing all of the shares of NPI, whose ownership of all of the shares of NPDI includes the business of distributing electricity to the customers within the former Town of Delhi, the westerly half of the former City of Nanticoke, the former Village of Port Rowan and the former Town of Simcoe. The County is satisfied that the price to be received is fair and reasonable, based on staff advice and the recommendations of the NPI board of directors. The County also retained the services of Borden Ladner Gervais LLP to advise and assist in conducting a competitive request for proposal process which has resulted in the sale of the shares of the Corporation. As the purchaser, HOI used the commercial value of underlying assets in determining the value of NPI. HOI considered other components of the financial statements as well as cash flow projections, an assessment of asset condition, one-time costs of integration and potential efficiency gains in assessing the value of the business. Please refer to section 1.6.2 for discussion regarding future rate levels.

1.8.2 If the price paid as part of the proposed transaction is significantly more than the book value of the assets of the selling utility, please provide details as to why this price will not have an adverse affect on the economic viability of the acquiring utility.

The premium paid over the book value on the transaction will not have a material impact on HONI's financial viability. In addition, the premium paid will not be included in Hydro One Distribution revenue requirement and thus will not be funded by ratepayers.

1.8.3 Please provide details of the financing of the proposed transaction.

HOI will initially finance the proposed transaction through cash or its short-term commercial paper

program, which is operational and fully backed by a syndicated bank line of credit maturing June, 2017. Long-term financing will be through its Medium-Term Note program which is fully operational and valid until September, 2013, and planned to be renewed thereafter.

1.8.4 If the proposed transaction involves a leasing arrangement, please identify separately any assets in the service area that are owned, from those assets that are encumbered by any means, e.g., subject to a lease or debt covenant.

No leasing arrangements are contemplated by the proposed transaction.

1.8.5 Please outline the capital (debt/equity) structure, on an actual basis, of the parties to the proposed transaction prior to the transaction and on a pro forma basis after completion of the proposed transaction. In order to allow the Board to assess any potential impacts on the utility's financial viability, please include the terms associated with the debt structure of the utility as well as the utility's dividend policy after the completion of the proposed transaction. Please ensure that any debt covenants associated with the debt issue are also disclosed.

The premium paid over the book value on the transaction will not have a material impact on HONI's or HOI's financial viability. In addition, the premium paid will not be included in HONI Distribution's revenue requirement and thus will not be funded by ratepayers.

1.8.6 Please provide details of any potential liabilities associated with the proposed transaction in relation to public health and safety matters or environmental matters. These may be matters that have been identified in the audited financial statements or they may be matters that the parties have become aware of since the release of the most recently audited financial statements. If there are any pre-existing potential liabilities regarding public health and safety matters or environmental matters for any party to the proposed transaction, provide details on how the parties propose to deal with those potential liabilities after the transaction is completed. Specify who will have on-going liability for the pre-existing potential liabilities.

Certain environmental concerns were disclosed by the Corporation of Norfolk County as part of the request for proposal process and as part of its disclosures under the Agreement. Liability for these matter remains momentarily with NPDI until the properties subject to the environmental concerns are transferred to HONI through the contemplated share transfer. HONI manages a distribution business throughout the Province with similar assets and has programs in place to deal with any relevant safety and environmental matters.

1.9 Other Information

1.9.1 If the proposed transaction requires the approval of a parent company, municipal council or any other entity please provide a copy of appropriate resolutions indicating that all such parties have approved the proposed transaction.

A copy of the resolution of the Corporation of Norfolk County dated April 2, 2013 authorizing the sale of shares to HOI is provided as **Exhibit A, Tab 3, Schedule 1, Attachment 13.**

1.9.2 Please list all suits, actions, investigations, inquiries or proceedings by any government body, or other legal or administrative proceeding, except proceedings before the Board, that have been instituted or threatened against each of the parties to the proposed transaction or any of their respective affiliates.

There are none associated with the parties to this application.

1.9.3 Regarding net metering thresholds, the Board will, absent exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Please indicate the current net metering thresholds of the utilities involved in the proposed transaction. Please also indicate if there are any special circumstances that may warrant the Board using a different methodology to determine the net metering threshold for the new or remaining utility.

The current net metering thresholds of HONI Distribution and NPDI are 14,330 kW and 701 kW respectively. There are no special circumstances that warrant the Board using a different methodology to determine the net metering threshold for the consolidated utility. Therefore, HONI Distribution and NPDI submit that the Board should add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new consolidated utility (15,031 kW).

1.9.4 Please provide the Board with any other information that is relevant to the application. When providing this additional information, please have due regard to the Board's objectives in relation to electricity.

This transaction was completed on a competitive, commercial basis between a willing seller and willing buyer. It is a demonstration of the type of benefits that can be realized from consolidation within the electric distribution sector in Ontario and is consistent with the findings of the Sector Review Panel. This transaction eliminates the duplication of effort between HONI Distribution and NPDI and results in a single electric distribution service provider for all of Norfolk County, which will ultimately lead to a lower cost of service across the HONI Distribution and NPDI service areas and will create downward pressure on electricity distribution rates.

PART II: CERTIFICATION AND ACKNOWLEDGMENT

2.1 Certification and Acknowledgment

I certify that the information contained in this application and in documents provided are true and accurate.

Signature of Key Individual	Print Name of Key Individual	Title/Position
ORIGINAL SIGNED BY RICK STEVENS	Rick Stevens	VP Customer Service
	Date April 24, 2013	Company Hydro One Inc.

Signature of Key Individual	Print Name of Key Individual	Title/Position
ORIGINAL SIGNED BY DENNIS TRAVALE	Dennis Travale	Mayor
	Date April 24, 2013	Company The Corporation of Norfolk County

Signature of Key Individual	Print Name of Key Individual	Title/Position
ORIGINAL SIGNED BY AIAN HAYS	Alan H. Hays	Chair
	Date April 24, 2013	Company Norfolk Power Inc.

(Must be signed by a key individual. A key individual is one that is responsible for executing the following functions for the applicant: matters related to regulatory requirements and conduct, financial matters and technical matters. These key individuals may include the Chief Executive Officer, the Chief Financial Officer, other officers, directors or proprietors.) TOR01: 5157356: v2

Ontario

Electricity Distribution Licence

ED-2002-0521

Norfolk Power Distribution Inc.

Valid Until

October 21, 2023

Mark C. Garner
Managing Director, Market Operations
Ontario Energy Board
Date of Issuance: October 22, 2003
Date of Amendment: January 26, 2006

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

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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 Norfolk Power Distribution Inc.

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

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

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

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

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

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

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

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

2 Interpretation

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

3 Authorization

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

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

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

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

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

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

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

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

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

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

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

11 Distribution Rates

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

12 Separation of Business Activities

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

13 Expansion of Distribution System

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

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

14 Provision of Information to the Board

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

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

14.3 The Licensee shall:

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

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

15 Restrictions on Provision of Information

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

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

17 Term of Licence

17.1 This Licence shall take effect on October 22, 2003 and expire on October 21, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

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

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

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

1. The westerly half of the former City of Nanticoke within the Municipality of the Town of Norfolk as of December 31, 2000.

2. The former Town of Delhi (in the former Township of Delhi) within the Municipality of the Town of Norfolk as of December 31, 2000.

3. The former Town of Port Rowan (in the former Township of Norfolk) within the Municipality of the Town of Norfolk as of December 31, 2000; and Villages of Long Point Bay, Phase 7, Registered Plan #37M-23, Block 36 & Block 37, Lot #3 to 14 and Lot #17 to 35 being the customers identified in a list provided by Norfolk Power as part of its amended application.

4. The former Town of Simcoe within the Municipality of the Town of Norfolk as of December 31, 2000.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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

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

SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

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 IMO includes interim payments made by the IMO.

2. Information Given to IMO

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

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 and 79.5 of the *Ontario Energy Board Act, 1998*.

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

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 and 79.5 of the *Ontario Energy Board Act, 1998*.

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

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

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

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 IMO, 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 and 79.5 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

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 IMO 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 IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

VT INCEPIT FIDELIS SIC PERMANET
Ontario

Electricity Distribution Licence

ED-2003-0043

Hydro One Networks Inc.

Valid Until

September 28, 2024

Original signed by

____
Theodore Antonopoulos
Manager, Electricity Rates
Ontario Energy Board

Date of Issuance: September 29, 2004
Date of Last Amendment: December 21, 2012

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

LIST OF AMENDMENTS

Board File No.	Date of Amendment
EB-2005-0286	October 12, 2005
EB-2007-0688	November 26, 2007
EB-2007-0912	February 1, 2008
EB-2007-0916	February 27, 2008
EB-2007-0968	March 20, 2008
EB-2007-0792	April 4, 2008
EB-2007-0933	June 26, 2008
EB-2007-0917	July 25, 2008
EB-2008-0269	October 22, 2008
EB-2009-0148	June 3, 2009
EB-2009-0325	November 24, 2009
EB-2009-0325	December 14, 2009
EB-2010-0172	August 26, 2010
EB-2010-0215	November 12, 2010
EB-2010-0282	January 13, 2011
EB-2010-0229	March 7, 2011
EB-2010-0398	March 29, 2011
EB-2011-0018	April 25, 2011
EB-2011-0067	May 18, 2011
EB-2011-0209	September 12, 2011
EB-2011-0118	October 11, 2011
EB-2011-0321	November 9, 2011
EB-2012-0007	March 8, 2012
EB-2012-0088	May 10, 2012
EB-2012-0204	July 5, 2012
EB-2012-0305	September 27, 2012
EB-2012-0343	November 8, 2012
EB-2012-0384	December 21, 2012

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1 Definitions

In this Licence:

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

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

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

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

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

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

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

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

"**Licensee**" means Hydro One Networks Inc.

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

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

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

"**OPA**" means the Ontario Power Authority;

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

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

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

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

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

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

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

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

2 Interpretation

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

3 Authorization

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

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

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

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

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

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

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

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

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

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

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

11 Distribution Rates

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

12 Separation of Business Activities

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

13 Expansion of Distribution System

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

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

14 Provision of Information to the Board

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

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

14.3 The Licensee shall:

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

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

15 Restrictions on Provision of Information

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

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

17 Term of Licence

17.1 This Licence shall take effect on September 29, 2004 and expire on September 28, 2024. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

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

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

21 Conservation and Demand Management

21.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 213.660 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 1,130.210 GWh (collectively the "CDM Targets"), over a four-year period beginning January 1, 2011.

21.2 The Licensee shall meet its CDM Targets through:

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

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

c) a combination of a) and b).

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

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

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

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

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

1. Municipalities as set out in Appendix B – Tab 1.

2. First Nation Reserves as set out in Appendix B – Tab 2.

3. Unorganized Townships as set out in Appendix B – Tab 3.

4. Municipalities in which a portion of the municipality is served by the Licensee and another portion of the municipality is served by another distributor. as set out in Appendix B – Tab 4.

5. Consumers embedded within another distributor but served by the Licensee as set out in Appendix B – Tab 5.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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

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

SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

1. The Licensee is exempt from the provisions of the Standard Supply Service Code for Electricity Distributors requiring time-of-use pricing for RPP consumers with eligible time-of-use meters, as of the mandatory date. This exemption applies only for service to approximately 122,000 of the identified hard to reach customers who, as of October 31, 2012 and as per Decision and Order EB-2012-0384, are outside the reach of the Licensee's smart meter telecommunications infrastructure. This exemption expires December 31, 2014.

2. The Licensee is exempt from the requirement of section 6.2.4.1e(i) of the Distribution System Code with respect to the following 12 generation projects, as per the Board's Decision and Order in EB-2010-0229:

Project ID	Generator Name	Project Name
11,690	Grand Valley Wind Farms Inc.	Grand Valley Wind Farms (Phase 2)
11,700	Invenergy Wind Centre ULC	Conestogo Wind Centre 2
11,720	Conestogo Wind, LP	Conestogo Wind Centre
11,870	International Power Canada, Inc.	Plateau I and II Wind
12,270	Pukwis Wind Partner Inc. & Pukwis Energy Co-op	Pukwis Community Wind Park
12,290	Glead Power Corporation	22.5 MW Ostrander Wind Farm
12,430	Grey Highlands Clean Energy LP	Grey Highlands Clean Energy
12,610	ZEP Wind Farm Ganaraska LP	ZEP Wind Farm Ganaraska
12,750	Clean Breeze Wind Park LP	Clean Breeze Wind Park
12,800	Southbranch Wind Farm Inc.	Southbranch Wind Farm
12,810	WPD Canada Corporation	Sumac Ridge Wind Farm
12,860	WPD Canada Corporation	Fairview Wind Farm

3. As per the Board's Decision and Order in EB-2011-0067, for generation facilities for which the primary energy source is water with a capacity not exceeding 10 megawatts and that are located on provincial Crown or federally-regulated lands and for which the electrical connection is to the distribution system owned by Hydro One Networks Inc. ("Hydro One"), Hydro One shall be exempted from the current connection cost deposit stipulated in s. 6.2.18(a) of the Distribution System Code (the"DSC") and shall, instead, adhere to the following schedule:

   (a) $20,000 per MW of capacity shall be paid by the proponent to Hydro One upon the execution of the Connection Cost Agreement.

   (b) An additional deposit in the amount of 30% of the total estimated cost, as estimated by Hydro One, less the amount received by Hydro One under paragraph (a) above, shall be paid by the proponent to Hydro One no later than 6 months after the proponent notifies Hydro One that it has issued its statement of completion under the earlier of the Waterpower Class Environmental Assessment and the equivalent environmental assessment process under the Canadian Environmental Assessment Act.

   (c) No later than 180 days after Hydro One receives payment of the amount referenced in paragraph (b) above, Hydro One shall provide to the proponent a construction schedule and a more accurate estimate of the project cost, if such estimate is requested and paid for by the proponent. The payment for the estimate shall be drawn from the deposit to the extent possible.

(d) The balance of the total estimated cost, as estimated by Hydro One based upon the best available information, shall be paid by the proponent to Hydro One no later than 30 days after the proponent notifies Hydro One that it has received the last of its necessary construction approval permits under Ontario's Lakes and Rivers Improvement Act or the Dominion Water Power Act.

(e) Hydro One and the proponent shall mutually agree upon an in-service date that is no later than 2 years after Hydro One receives the balance referenced in paragraph (d), above, subject to the following: in cases where a transmission upgrade or new transmission facilities are required, Hydro One and the proponent may agree to an in-service date that is later than two years after Hydro One receives the balance referenced in paragraph (d), above.

(f) The Expansion Deposit, as stipulated by Section 3.2.20 of the DSC, shall be paid to Hydro One at the same time as the payment in paragraph (d).

Notwithstanding the foregoing, if at any time the above-noted payments to Hydro One are insufficient to cover Hydro One's costs as estimated by Hydro One, the proponent shall pay, to Hydro One, additional funding sufficient to meet the shortfall identified by Hydro One, and Hydro One shall be relieved of its obligation to perform such further work until it receives the said additional funding.

4. For the Trout Creek Wind Farm (Hydro One Project #12,780), Hydro One shall be exempted from the current connection cost deposit stipulated in s. 6.2.18(a) of the Distribution System Code (the "DSC") and shall, instead, adhere to the following schedule:

(a) $20,000 per MW of capacity shall be paid by the proponent to Hydro One upon the execution of the Connection Cost Agreement.

(b) An additional deposit in the amount of 30% of the total estimated cost, as estimated by Hydro One, less the amount received by Hydro One under paragraph (a) above, shall be paid by the proponent to Hydro One no later than 4 months after the proponent notifies Hydro One that it has completed the Renewable Energy Approval.

(c) No later than 180 days after Hydro One receives payment of the amount referenced in paragraph (b) above, Hydro One shall provide to the proponent a construction schedule and a more accurate estimate of the project cost, if such estimate is requested and paid for by the proponent. The payment for the estimate shall be drawn from the deposit to the extent possible.

(d) The balance of the total estimated cost, as estimated by Hydro One based upon the best available information, shall be paid by the proponent to Hydro One no later than 30 days after the proponent notifies Hydro One that it is proceeding to construction. If this notification is not given by September 30, 2013, then the proponent’s capacity allocation shall be removed.

(e) Hydro One and the proponent shall mutually agree upon an in-service date that is no later than 2 years after Hydro One receives the balance referenced in paragraph (d), above, subject to the following: in cases where a transmission upgrade or new transmission facilities are required, Hydro One and the proponent may agree to an in-service date that is later than two years after Hydro One receives the balance referenced in paragraph (d), above.

(f) The Expansion Deposit, as stipulated by Section 3.2.20 of the DSC shall be paid to Hydro One at the same time as the payment in paragraph (d).

Notwithstanding the foregoing, if at any time the above-noted payments to Hydro One are insufficient to cover Hydro One's costs as estimated by Hydro One, the proponent shall pay, to Hydro One, additional funding sufficient to meet the shortfall identified by Hydro One, and Hydro One shall be relieved of its obligation to perform such further work until it receives the said additional funding.

5. As per the Board's Decision and Order in EB-2012-0343:

(a) The Licensee is exempt from section 6.2.6 of the Distribution System Code for micro-embedded generation projects that are an indirect connection requiring a site assessment. This exemption expires August 3, 2013 or six months after the conclusion of the Board's consultation EB-2012-0246, whichever is earlier. During the period of exemption, for micro-embedded generation projects that are an indirect connection requiring a site assessment, the Licensee shall be required to issue an offer to connect or issue reasons for refusal within 30 days, for at least 90% of applications. If a customer requests a delay with respect to 6.2.6, the additional time will be added to the timeline. Hydro One Networks Inc. shall track its compliance with this provision. For all projects other than micro-embedded generation projects that are an indirect connection requiring a site assessment, the application of section 6.2.6 of the Distribution System Code shall remain unchanged.

(b) The Licensee is exempt from the provisions of 6.2.7 of the Distribution System Code for micro-embedded generation applications. This exemption expires August 3, 2013 or six months after the conclusion of the Board's consultation EB-2012-0246, whichever is earlier. During the period of exemption, the Licensee shall comply with the provisions of sections 7.2.1 and 7.2.3 of the Distribution System Code.

SCHEDULE 4 LIST OF RRR EXEMPTIONS

The Licensee is exempt from the following sections of the Electricity Reporting and Record Keeping Requirements:

1. Section 2.1.5.5 (b)

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

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

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

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

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

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

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

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

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

3. Pass Through of Rebate

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

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

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

c embedded distributors to whom the distributor distributes electricity.

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

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

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.
Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

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

ONTARIO POWER GENERATION INC. REBATES

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

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

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

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

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

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

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

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

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

3. Pass Through of Rebate

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

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

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

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.
If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

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

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

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

APPENDIX B

TAB 1 MUNICIPALITIES

Name of Municipality:	Township of Addington Highlands
Formerly Known as:	Township of Denbign, Abinger and Ashby, Township of Anglesea and Effingham, Kaladar, as at December 31. 1999.
Name of Municipality:	Township of Adelaide Metcalfe
Formerly Known As:	Township of Adelaide, Township of Metcalfe, as at December 31, 2000.
Name of Municipality:	Township of Adjala-Tosorontio
Formerly Known As:	Portions of the Township of Adjala, Township of Tosorontio, Township of Sunnidale, as at December 31, 1993.
Name of Municipality:	Township of Admaston/Bromley
Formerly Known As:	Township of Admaston, Township of Bromley, as at December 31, 1999.
Name of Municipality:	Township of Alberton as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Algonquin Highlands, (Formerly known as Township of Sherborne, Stanhope, McClintock, Livingstone, Lawrence and Nightingale)
Formerly Known As:	Township of Sherborne et al,Township of Stanhope, as at December 31, 2000.
Name of Municipality:	Township of Alnwick/Haldimand
Formerly Known As:	Township of Alnwick, Township of Haldimand, as at December 31, 2000.
Name of Municipality:	Township of Amaranth as at March 31, 1999.
Formerly Known As:	Same

Name of Municipality: Township of The Archipelago as at March 31, 1999.
Formerly Known As: Conger, Cowper, Harrison, Henvey, Wallbridge plus geographic/unorganized townships and unsurveyed areas

Name of Municipality: Township of Armour as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Armstrong as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Arnprior as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Arran-Elderslie
Formerly Known As: Township of Arran, Township of Elderslie, Town of Chesley, Village of Tara, Village of Paisley, as at December 31, 1998.

Name of Municipality: Township of Ashfield-Colborne-Wawanosh
Formerly Known As: Township of Ashfield, Township of West Wananosh, Township of Colborne, as at December 31, 2000.

Name of Municipality: Township of Assiginack as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Athens
Formerly Known As: Township of Rear of Young and Escott, Village of Athens, as at December 31, 2000.

Name of Municipality: Township of Augusta as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Baldwin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Bancroft
Formerly Known As: Town of Bancroft, Township of Dungannon, as at December 31, 1998.

Name of Municipality: Township of Barrie Island as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Bayham
Formerly Known As: Township of Baymen, Village of Port Burwell, Village of Vienna, as at December 31, 1997.

Name of Municipality: Township of Beckwith as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Billings as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Black River-Matheson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Blind River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Bonfield as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Bonnechere Valley
Formerly Known As: Village of Eganville, Township of Grattan, Township of Sebastopol, Township of South Algona, as at December 31, 2000.

Name of Municipality: Township of Brethour as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Brighton
Formerly Known As: Town of Brighton, Township of Brighton, as at December 31, 2001.

Name of Municipality: City of Brockville as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Brudenell, Lyndoch and Raglan
Formerly Known As: Township of Brudenell and Lyndoch, Township of Raglan, as at December 31, 1998.

Name of Municipality: Township of Burpee and Mills
Formerly Known As: Township of Burpee, Unorganized Twp of Mills, as at December 31, 1997.

Name of Municipality: Town of Caledon
Formerly Known As: Township of Albion, Township of Caledon, Village of Bolton, Village of Caledon East, Township of Chinguacousy (part), as at December 31, 1973.

Name of Municipality: Township of Calvin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Carleton Place as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Carling as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Carlow/Mayo
Formerly Known As: Township of Carlow, Township of Mayo, as at December 31, 2000.

Name of Municipality: Township of Casey as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Cavan-Millbrook-North Monoghan
Formerly Known As: Township of Cavan, Township of North Monaghan,
Village of Millbrook, as at December 31, 1997.

Name of Municipality: Township of Central Frontenac
Formerly Known As: Township of Hinchinbrooke, Township of Kennebec, Township of Olden, Township of Oso, as at December 31, 1997.

Name of Municipality: Township of Central Manitoulin
Formerly Known As: Twp. Of Carnarvon, Unorganized Twp of Sandfield, as at April 30, 1997.

Name of Municipality: Municipality of Centre Hastings
Formerly Known As: Village of Madoc, Township of Huntingdon, as at December 31, 1997.

Name of Municipality: Township of Chamberlain as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Champlain
Formerly Known As: Village of L'Orignal, Township of West Hawkesbury, Township of Longueuil, Town of Vankleek Hill, as at December 31, 1997.

Name of Municipality: Township of Chapple as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Charlton and Dack
Formerly Known As: Town of Charlton, Township of Dack, as at December 31, 2002.

Name of Municipality: Township of Chatsworth
Formerly Known As: Village of Chatsworth, Township of Holland, Township of Sullivan, as at December 31, 1999.

Name of Municipality: Township of Chisolm as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Clarence-Rockland
Formerly Known As: Town of Rockland, Township of Clarence, as at December 31, 1997.

Name of Municipality: Town of Cobalt as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Cockburn Island as at March 31, 1999
Formerly Known As: Same

Name of Municipality: Township of Coleman as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Conmee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Dawn-Euphemia
Formerly Known As: Township of Dawn, Township of Euphemia, as at December 31, 1997.

Name of Municipality: Township of Dawson
Formerly Known As: Township of Atwood, Township of Blue,
Township of Worthington, Township of Dilke, as at December 31, 1996.

Name of Municipality: Town of Deep River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Deseronto as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Dorion as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Douro-Dummer
Formerly Known As: Township of Douro, Township of Dummer, as at December 31, 1997.

Name of Municipality: Township of Drummond/North Elmsley
Formerly Known As: Township of Drummond, Township of North Elmsley, as at December 31, 1997.

Name of Municipality: City of Dryden
Formerly Known As: Town of Dryden, Township of Barclay

Name of Municipality: Township of Dysart et al as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Ear Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of East Ferris as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of East Garafraxa as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of East Hawkesbury as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Elizabethtown-Kitley
Formerly Known As: Township of Kitley, Township of Elizabethtown as at December 31, 2000.

Name of Municipality: City of Elliott Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Emo, as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Englehart as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Enniskillen as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Erin
Formerly Known As: Township of Erin, Village of Erin, as at December 31, 1997.

Name of Municipality: Township of Evantural as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Faraday as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Fauquier-Strickland as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of French River
Formerly Known As: Township of Cosby, Township of Mason, Township of Martland, geographic/unorganized townships of Delamere, Hoskin and Scollard in whole and Bigwood, Cherriman and Haddo in part, as at December 31, 1998.

Name of Municipality: Township of Front of Yonge as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Frontenac Islands
Formerly Known As: Township of Howe Island, Township of Wolfe Island, as at December 31, 1997.

Name of Municipality: Township of Galway-Cavendish and Harvey
Formerly Known As: Township of Galway and Cavandish, Township of Harvey, as at December 31, 1997.

Name of Municipality: Township of Gauthier as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Georgian Bay as at March 31, 1999.
Formerly Known As: Township of Freeman, Township of Gibson, Township of Baxter.

Name of Municipality: Township of Georgian Bluffs
Formerly Known As: Township of Derby, Township of Keppel, Township of Sarawak, as at December 31, 2000.

Name of Municipality:	Town of Georgina as at March 31, 1999.
Formerly Known As:	Township of North Gwillimbury, Township of Georgina.
Name of Municipality:	Township of Gillies as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Gordon as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Town of Gore Bay as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Greater Madawaska
Formerly Known As:	Township of Bagot, Blythfield and Brougham, Township of Griffith, and Matawatchan, (Jan 1998: Township of Bagot and Blythfield, Township of Brougham amalgamated into Township of Bagot, Blythfield and Brougham), as at December 31, 2000.
Name of Municipality:	Town of Greater Napanee
Formerly Known As:	Township of Adolphustown, Township of North Fredericksburgh, Township of South Fredericksburgh, Township of Richmond, Town of Napanee, as at December 31, 1997.
Name of Municipality:	Municipality of Greenstone
Formerly Known As:	Town of Geraldton, Town of Longlac, Township of Beardmore, Township of Nakina, as at December 31, 2000.
Name of Municipality:	Municipality of Grey Highlands
Formerly Known As:	Township of Artemesia, Township of Euphrasia Village of Markdale, Township of Osprey, as at December 31, 2000.
Name of Municipality:	Township of Hamilton as at March 31, 1999.
Formerly Known As:	Same

Name of Municipality: Township of Harley as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Harris as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Hastings Highlands
Formerly Known As: Township of Bangor, Wicklow and McClure, Township of Herschel, Township of Monteagle, as at December 31, 2000.

Name of Municipality: Township of Havelock-Belmont-Methuen
Formerly Known As: Township of Belmont and Methuen, Village of Havelock, as at December 31, 1997.

Name of Municipality: Township of Head, Clara and Maria, as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Highland East
Formerly Known As: Township of Bicroft, Township Cardiff, Township of Glamorgan, Township of Monmouth, as at December 31, 2000.

Name of Municipality: Township of Hilliard as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Hornpayne as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Horton as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: The Township of Howick as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Hudson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality:	Township of Ignace as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of James as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Joly as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	The City of Kawartha Lakes
Formerly Known As:	County of Victoria, Town of Lindsay, Municipality of Bobcaygeon/ Verulam, Village of Fenelon Falls, Village of Omemee, Village of Sturgeon Point, Village of Woodville, Township of Bexley, Township of Carden/Dalton, Township of Eldon, Township of Emily, Township of Fenelon, Township of Laxton, Digby and Longford, Township Manvers, Township of Mariposa, Township of Ops, Township of Somerville, (Jan 2000: Township of Carden , Township of Dalton amalgamated into Township of Carden/Dalton), (Jan 2000; Village of Bobcaygeon/Township of Verulam amalgamated into the Municipality of Bobcaygeon/Verulam), as at December 31, 2000.
Name of Municipality:	Town of Kearney as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Kerns as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Municipality of Killarney
Formerly Known As:	Townships of Rutherford and George Island and the geographic/unorganized townships of, Allen, Atlee, Goschen, Hansen, Killarney, Kilpatrick, Sale, Struthers, Travers, and portions of the geographic/unorganized townships of Bigwood, Carlyle, Humboldt, Mowat, and unsurveyed territory and islands, as at Deember 31, 1998.

Name of Municipality: Town of Kirkland Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of La Vallee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Lake of Bays as at March 31, 1999.
Formerly Known As: Township of McLean, Township of Ridout, Township of Franklin, Township of Sinclair, Township of Finlayson.

Name of Municipality: Township of Lake of the Woods
Formerly Known As: Township of McCrosson and Tovell, Township of of Morson, unorganized islands in Kenora District and Rainy River District, as at December 31, 1998.

Name of Municipality: Municipality of Lambton Shores
Formerly Known As: Village of Arkona, Town of Bosanquet, Town of Forest, Village of Grand Bend, Village of Thedford, as at December 31, 2000.

Name of Municipality: Township of Lanark Highlands
Formerly Known As: Township of Darling, Township of North West Lanark, (May 1997: Lavant, Dalhousie and North Sherbrook Township/Township Lanark/Village Lanark amalgamated into Township of North West Lanark), as at June 30, 1996.

Name of Municipality: Township of Larder Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Latchford as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Laurentian Hills
Formerly Known As: Township of Rolph, Township of Wylie and McKay, Village of Chalk River, as at December 31, 1999.

Name of Municipality: Township of Laurentian Valley
Formerly Known As: Township of Stafford and Pembroke, Township of Alice and Fraser, as at December 31, 1999.

Name of Municipality: Township of Limerick as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Loyalist
Formerly Known As: Township of Amherst Island, Township of Ernestown, Village of Bath, as at December 31, 1997.

Name of Municipality: Township of Lucan Biddulph
Formerly Known As: Village of Lucan, Township of Biddulph, Police Village of Granton, as at December 31, 1998.

Name of Municipality: Township of Machar as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Machin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Madawaska Valley
Formerly Known As: Village of Barry's Bay, Township of Radcliffe, Township of Sherwood, Jones and Burns, as at December 31, 2000.
Name of Municipality: Township of Madoc as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Malahide
Formerly Known As: Township of Malahide, Township of Dorchester, Village of Springfield, as at December 31, 1997.

Name of Municipality: Township of Manitouwadge as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mapleton
Formerly Known As: Township of Mapleton, Township of Maryborough, (Jan 1998-Village of Drayton, Township of Peel amalgamated into the Township of Mapleton), as at December 31, 1998.

Name of Municipality: Town of Marathon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Markstay-Warren
Formerly Known As: Township of Hagar, Township of Ratter and Dunnet, geographic/unorganized township of Awrey and portions of the geographic/unorganized townships of Hawley, Henry, Loughrin, Street, as at December 31, 1998.

Name of Municipality: Municipality of Marmora and Lake
Formerly Known As: Township of Marmora and Lake, Village of Marmora, (Jan 1998: Village of Deloro, Township of Marmora and Lake amalgamated into the Township of Marmora and Lake, as at December 31, 1997.
Name of Municipality: Township of Matachewan as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Mattawa as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mattawan as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mattice-Val Cote as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of McDougall
Formerly Known As: Township of McDougall, geographic/unorganized township of Ferguson, as at December 31, 1999.

Name of Municipality: Township of McGarry as at March 31, 1999.
Formerly Known As: Same

Name of Municipality:	Township of McKellar as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of McMurrich/Monteith
Formerly Known As:	Township of McMurrich, geographic/unorganized township of Monteith (eastern portion), as at December 31, 1997.
Name of Municipality:	Township of McNab/Braeside
Formerly Known As:	Township of McNab, Village Braeside, as at December 31, 1997
Name of Municipality:	Municipality of Meaford (formerly known as Town of Georgian Highlands)
Formerly Known As:	Township of St. Vincent, Township of Sydenham, Town of Meaford, as at December 31, 2000.
Name of Municipality:	Township of Melancthon as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Village of Merrickville-Wolford
Formerly Known As:	Township of Wolford, Village of Merrickville, as at December 31, 1997.
Name of Municipality:	Township of Middlesex Centre
Formerly Known As:	Township of Lobo, Township of London, Township of Delaware, Police Village of Delaware, as at December 31, 1998.
Name of Municipality:	Township of Minden Hills
Formerly Known As:	Township of Anson, Hindon and Minden, Township of Lutterworth, Township of Snowdon, as at December 31, 2000.
Name of Municipality :	Town of Mono as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Montague as at March 31, 1999.
Formerly Known As:	Same

Name of Municipality: Township of Moonbeam as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Moosonee as at March 31, 1999.
Formerly Known As: Moosonee Development Board

Name of Municipality: Township of Morley
Formerly Known As: Township of Morley, geographic/unorganized townships Twp's of Dewart and Sifton, as at December 31, 2003.

Name of Municipality: Municipality of Morris-Turnberry
Formerly Known As: Township of Morris, Township of Turnberry, as at December 31, 2000.

Name of Municipality: Township of Mulmar as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Muskoka Lakes as at March 31, 1999.
Formerly Known As: Township of Cardwell, Township of Watt, Township of Medora, Township of Monck, Township of Wood.

Name of Municipality: Township of Nairn and Hyman
Formerly Known As: Township of Nairn, Unorganized Township of Hyman, as at December 31, 1997.

Name of Municipality: The Nation Municipality
Formerly Known As: Township of Cambridge, Township of South Plantagenet, Village of St. Isidore, Township of Caledonia, as December 31, 1997.

Name of Municipality: Municipality of Neebing as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Temiskaming Shores
Formerly Known As: **T**own of New Liskeard, Town of Haileybury, Township of Dymond, as at December 31, 2003.

Name of Municipality: Township of Nipigon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Nipissing as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Algona-Wilberforce
Formerly Known As: Township of North Algona, Township of Wilberforce, as at December 31, 1998.

Name of Municipality: Municipality of Northern Bruce Peninsula
Formerly Known As: Township of St. Edmunds, Township of Lindsay, Township of Eastnor, Village of Lion's Head, as at December 31, 1998.

Name of Municipality: Township of North Dundas
Formerly Known As: Township of Mountain, Township of Winchester, Village of Chesterville, Village of Winchester, as at December 31, 1997.

Name of Municipality: Township of North Frontenac
Formerly Known As: Township of Barrie, Township of Clarendon,
Township of Miller, Township of Palmerston, Township of North Canonto,
Township of South Canonto, as at December 31, 1997.

Name of Municipality: Township of North Glengarry
Formerly Known As: Township of Kenyon, Township of Lochiel, Town of Alexandria, Village of Maxville, Police Village of Apple Hill, as at December 31, 1997.

Name of Municipality: Township of North Grenville
Formerly Known As: Township of Oxford-on-Rideau, Town of Kemptville, Township of South Gower, as at December 31, 1997.

Name of Municipality: Township of North Himsworth as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Kawartha
Formerly Known As: Township of Burleigh and Anstruther, Township of Chandos, as at December 31, 1997.

Name of Municipality: Town of North Perth
Formerly Known As: Township of Wallace, Township of Elma, Town of Listowel, as at December 31, 1997.

Name of Municipality: Township of The North Shore as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Stormont
Formerly Known As: Township of Finch, Township of Roxborough, Village of Finch, Police Village of Avonmore (in the Township of Roxborough), as at December 31, 1997.

Name of Municipality: Town of Northeastern Manitoulin and the Islands
Formerly Known As: Township of Howland, Town of Little Current, all islands not part of other municipalities on Manitoulin Island, as at December 31, 1997.

Name of Municipality: Township of O'Conner as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Oliver Paipoonge
Formerly Known As: Township of Oliver, Township of Paipoonge, as at December 31, 1997.

Name of Municipality: Township of Opasatika as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Oro-Medonte
Formerly Known As: Portions of the Township of Medonte, Township of Oro, Township of Orillia, Township of Tay, Township of Flos, Township of Vespra, as at December 31, 1993.

Name of Municipality: Township of Otonabee-South Monaghan
Formerly Known As: Township of Otonabee, Township of South Monaghan, as at December 1, 1999.

Name of Municipality: City of Owen Sound as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Papineau-Cameron as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Perry as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Pelee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: The Township of Perth South
Formerly Known As: Township of Downie, Township of Blanshard, as at December 31, 1997.

Name of Municipality: Town of Perth as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Petawawa
Formerly Known As: Village of Petawawa, Township of Petawawa, as at June 30, 1996.

Name of Municipality: Township of Pickle Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Plympton-Wyoming
Formerly Known As: Township of Plympton, Village of Wyoming, as at December 31, 2000.

Name of Municipality: Municipality of Powassan
Formerly Known As: Town of Powassan, Township of Himsworth South, Town of Trout Creek, as at December 31, 2000.

Name of Municipality: County of Prince Edward
Formerly Known As: County of Prince Edward, Town of Picton, Village of Bloomfield, Village of Wellington, Township of Ameliasburgh, Township of Athol, Township of Hallowell, Township of Hillier, Township of North Marysburgh, Township of South Marysburgh, Township of Sophiasburgh, as at December 31, 1997.

Name of Municipality: City of Quinte West
Formerly Known As: City of Trenton, Village of Frankford, Township of Sidney, Township of Murray, as at December 31, 1997.

Name of Municipality: Town of Rainy River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Ramara
Formerly Known As: Township of Mara, Township of Rama , as at December 31, 1993.
Name of Municipality: Township of Red Rock as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Rideau Lakes
Formerly Known As: Village of Newboro, Township of Bastard and South Burgess, Township of North Crosby, Township of South Crosby, Township of South Elmsley, as at December 31, 1997.

Name of Municipality: Township of Ryerson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Schreiber as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Seguin
Formerly Known As: Township of Humphrey, Township of Foley, Township of Christie, geographic/unorganized Township of Monteith (western portion), Village of Rosseau, as at December 31, 1997.

Name of Municipality: Township of Severn
Formerly Known As: Portions of Village of Coldwater, Township of Matchedash, Township of Medonte, Township of Orillia, Township of Tay, as at December 31, 1993.

Name of Municipality: Township of Shedden as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Shelburne as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Shuniah as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Sioux Narrows-Nestor Falls
Formerly Known As: Township of Sioux Narrows, all of the geographic/unorganized townships of Code, Devonshire, Godson, Manross, MacQuarrie, Phillips, Tweedsmuir, and Work, portions of the geographic/unorganized townships of LeMay, McKeekin in Kenora District, and the geographic/unorganized townships of Claxton, Croome, and Mathieu in the Rainy River District, as at December 31, 2000.

Name of Municipality: Separated Town of Smiths Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Smooth Rock Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of South Algonquin
Formerly Known As: Township of Airy and geographic/unincorporated townships of Dickens, Lyell, Murchison and Sabine, as at May 31, 1997.

Name of Municipality: Town of South Bruce Peninsula
Formerly Known As: Township of Albemarle, Township of Amabel, Town of Wiarton, Village of Hepworth, as at December 31, 1998.

Name of Municipality: Township of South Frontenac
Formerly Known As: Township of Bedford, Township of Loughborough, Township of Portland, Township of Storrington, as at December 31, 1997.

Name of Municipality: Village of South River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Southwest Middlesex
Formerly Known As: Township of Ekfrid, Township of Mosa, Village of Glencoe, Village of Wardsville, as at December 31, 2000.

Name of Municipality: Township of Southwold as at March 31, 1999.
Formerly Known As: Same
Name of Municipality: Township of Springwater
Formerly Known As: Portions of the former Village of Elmvale, Township of Flos, Township of Medonte, Township of Vespra, Town of Wasaga Beach, as at December 31, 1993.

Name of Municipality: Municipality of St. Charles
Formerly Known As: Township of Casimir, Jennings & Appleby and the geographic/unorganized townships of Cherriman and Haddo, as at December 31, 1998.

Name of Municipality: Township of St. Clair
Formerly Known As: Township of Sombra, Township of Moore, as at December 31, 2000.

Name of Municipality: Township of Stirling-Rawdon
Formerly Known As: Village of Stirling, Township of Rawdon, as at December 31, 1997.

Name of Municipality: Township of Stone Mills
Formerly Known As: Township of Camden East, Township of Sheffield, Village of Newburgh, as at December 31, 1997.

Name of Municipality: Township of Strong as at March 31, 1996.
Formerly Known As: Same

Name of Municipality: Township of Tay Valley
Formerly Known As: Township of South Sherbrooke, Township of Bathurst, Township of North Burgess, as at December 31, 1997.

Name of Municipality: Township of Tehkummah as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Temagami as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Terrace Bay as at March 31, 1999
Formerly Known As: Same
Name of Municipality: Municipality of Thames Centre
Formerly Known As: Township of North Dorchester, Township of West Nissouri, Village of Dorchester, Police Village of Thorndale, as at December 31, 2000.

Name of Municipality: Town of Thessalon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Village of Thornloe as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Thorold as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Timmins as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Tiny as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Trent Hills
Formerly Known As: Municipality of Campbellford/Seymour, Township of Percy, Village of Hastings, Police Village of Warkworth (Jan 1998-Town of Campbellford, Township of

Seymour amalgamated into the Municipality of Campbellford/Seymour), as at December 31, 2000.

Name of Municipality: Township of Tudor and Cashel as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Tweed
Formerly Known As: Village of Tweed, Township of Hungerford, Township of Elzevir and Gromsthorpe, as at December 31, 1997.

Name of Municipality: Township of Tyendinaga as at March 31, 1999.
Formerly Known As: Same
Name of Municipality: Township of Val Rita-Harty as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Wainfleet as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of West Elgin
Formerly Known As: Township of Aldborough, Village of West Lorne, Police Village of Rodney, as at December 31, 1997.

Name of Municipality: Town of Whitchurch-Stouffville as at March 31, 1999.
Formerly Known As: Village of Stouffville and portions of the Township of Whitchurch and the Township of Markham.

Name of Municipality: Township of White River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Whitestone
Formerly Known As: Township Hagerman, and the geographic/unorganized townships of Ferrie, McKenzie, East Burpee, and a portion of the Township of Magnetawan, as at December 31, 1999.

Name of Municipality: Township of Wollaston as at March 31, 1999.

Formerly Known As: Same

APPENDIX B

TAB 2 FIRST NATION RESERVES

Reserve Name: Abitibi I.R. No. 70
Band Name: Wahgoshig First Nation

Reserve Name: Alderville I.R No. 37
Band Name: Alderville First Nation

Reserve Name: Aroland Indian Settlement
Band Name: Aroland

Reserve Name: Big Grassy River I.R. No. 35G
Band Name: Big Grassy First Nation

Reserve Name: Big Island Mainland 93
Band Name: Anishnaabeg of Naongashiing

Reserve Name: Cape Croker Island I.R. No. 27, Neyaashiinigmiing Reserve
Band Name: Chippewas of Nawash First Nation

Reserve Name: Chippewas of the Thames
Band Name: Chippewas of the Thames First Nation

Reserve Name: Chapleau I.R. No. 74A
Band Name: Chapleau Ojibway First Nation

Reserve Name: Christian Island I.R. No.30
Band Name: Beausoleil First Nation

Reserve Name: Cockburn Island 19, 19A
Band Name: Zhiibaahaasing First Nation

Reserve Name: Constance Lake I.R. 92
Band Name: Constance Lake First Nations

Reserve Name: Couchiching I.R. No. 16A
Band Name: Couchiching First Nation

Reserve Name: Curve Lake I.R. No. 35
Band Name: Curve Lake First Nation

Reserve Name: Dalles I.R. No. 38C
Band Name: Ochiichagwe'babigo'ining First Nation

Reserve Name: Duck Lake R.R. No. 76B
Band Name: Brunswick House First Nation

Reserve Name: Dokis I.R. No. 9
Band Name: Dokis First Nation

Reserve Name: Eagle Lake I.R. No. 27
Band Name: Eagle Lake First Nation

Reserve Name: English River I.R. No.21
Band Name: Grassy Narrows First Nation

Reserve Name: Factory Island I.R. No. 1
Band Name: Moose Factory First Nation

Reserve Name: Georgina Island I.R. No. 33
Band Name: Chippewas of Georgina Island First Nation

Reserve Name: Gibson I.R. No. 31 Wahta mohawk
Band Name: Mohawks of Gibson

Reserve Name: Golden Lake No. 39
Band Name: Algonquins Golden Lake First Nation

Reserve Name: Henvey Inlet I.R. No. 2 French River I.R. 13
Band Name: Henvey Inlet First Nation

Reserve Name: Hiawatha I.R. No.36
Band Name: Ojibways of Hiawatha First Nation

Reserve Name: Islington I.R No. 29
Band Name: Wabasemoong Independent Nations

Reserve Name: Kenora I.R. No. 38B
Band Name: Wauzhushk Onigum Nation

Reserve Name: Kettle Point I.R. No. 44
Band Name: Chippewas of Kettle and Stony Point First Nation

Reserve Name: Lac des Milles Lacs I.R. 22A1, Seine River I.R. 22A2
Band Name: Lac des Milles Lacs

Reserve Name: Lac Suel I.R. No. 28
Band Name: Lac Suel Nation

Reserve Name: Lake Helen I.R. No. 53A
Band Name: Red Rock Band

Reserve Name: Long Lake I.R. No. 77
Band Name: Ginoogaming First Nation

Reserve Name: Long Lake I.R. No. 58
Band Name: Long Lake No. 58 First Nation

Reserve Name: Magnetewan I.R No. 1
Band Name: Magnetewan First Nation

Reserve Name: Manitou Rapids I.R. No. 11
Band Name: Rainy River First Nation

Reserve Name: Matachewan I.R 72
Band Name: Matachewan First Nation

Reserve Name: Mattagami I.R No.71
Band Name: Mattagami First Nation

Reserve Name: Mississagi River I.R No.8
Band Name: Mississauga First Nation

Reserve Name: Mobert I.R No. 82
Band Name: Pic Mobert First Nation

Reserve Name: Moose Point I.R No. 79
Band Name: Moose Deer Point First Nation

Reserve Name: Moravian I.R. No. 47
Band Name: Delaware First Nation

Reserve Name: Muncey Delaware Nation No. 1
Band Name: Munsee-Delaware First Nation

Reserve Name: Neguaguon Lake I.R No. 25d
Band Name: Lac La Croix First Nation

Reserve Name: New Credit I.R 40A
Band Name: Mississaugas of the New Credit First Nation

Reserve Name: New Post 69, 69a
Band Name: New Post First Nation

Reserve Name: Nipissing I.R No. 10
Band Name: Nipissing First Nation

Reserve Name: Northwest Angle I.R No. 33B and Whitefish Bay I.R. No. 33a
Band Name: Northwest Angle No. 33 First Nation

Reserve Name: Oneida I.R No. 41
Band Name: ONA YO TE'A:KA

Reserve Name: Osnaburgh I.R No. 63A, 63B
Band Name: Osnaburgh First Nation

Reserve Name: Parry Island I.R No. 16
Band Name: Wasauksing First Nation

Reserve Name: Pays Plat I.R. No. 51
Band Name: Pays Plat First Nation

Reserve Name: Pic River I..R. No. 50
Band Name: Ojibways of Pic River No. 50 First Nation

Reserve Name: Rainy Lake I.R No. 17A, 17B
Band Name: Naicatchewenin First Nation

Reserve Name: Rainy Lake I.R. 26A
Band Name: ` Nicickousemenecaning First Nation

Reserve Name: Rainy Lake I.R. No. 18c
Band Name: Stanjikoming First Nation

Reserve Name: Rama I.R. No. 32
Band Name: Chippewas of Mnjikaning First Nation
Reserve Name: Rat Portage I.R No. 38A
Band Name: Washagamis Bay First Nation

Reserve Name: Rocky Bay I.R. No. 1
Band Name: Rocky Bay First Nation

Reserve Name: Sabaskong Bay 32c, Whitefish Bay 32a, Yellow Girl Bay 32b
Band Name: Naotkamegwanning Anishnabe First Nation

Reserve Name: Sabaskong Bay I.R 35D
Band Name: Ojibways of Onegaming First Nation

Reserve Name: Sarnia I.R.No.45
Band Name: Chippewas of Sarnia

Reserve Name: Saug-A-Gaw-Sing I.R. No. 1
Band Name: Big Island First Nation

Reserve Name: Saugeen I.R. No. 29
Band Name: Chippewas of Saugeen First Nation

Reserve Name: Savant Lake Indian Settlement
Band Name: Saugeen Nation

Reserve Name: Scugog I.R No. 34
Band Name: Mississauga of Scugog First Nation

Reserve Name: Seine River I.R. No. 23A, 23B, Sturgeon Falls No. 23
Band Name: Seine River First Nation

Reserve Name: Serpent River I.R. No. 7
Band Name: Serpent River First Nation

Reserve Name: Shawanaga I.R. No. 17
Band Name: Shawanaga First Nation

Reserve Name: Sheguiandah I.R. No. 24
Band Name: Sheguiandah First Nation

Reserve Name: Sheshegwaning I.R. No. 20
Band Name: Sheshegwaning First Nation

Reserve Name: Shoal Lake I.R. No 39A
Band Name: Shoal Lake No. 39 First Nation

Reserve Name: Shoal Lake I.R. No 40
Band Name: Shoal Lake No. 40 First Nation

Reserve Name: Six Nations I.R. No. 40
Band Name: Six Nations of the Grand River Territory

Reserve Name: Slate Falls Indian Settlement
Band Name: Slate Falls Nation

Reserve Name: Spanish River I.R. No. 5
Band Name: Sagamok Anishnawbek

Reserve Name: Sucker Creek I.R NO. 23
Band Name: Sucker Creek First Nation

Reserve Name: Thessalon I.R. No. 12
Band Name: Thessalon First Nation

Reserve Name: Tyendinaga Mohawk Territory
Band Name: Mohawks of the Bay of Quinte

Reserve Name: Wabauskang 21
Band Name: Wabauskang First Nation

Reserve Name: Wabigoon Lake I.R No. 27
Band Name: Wabigoon Lake Ojibway Nation

Reserve Name: Wahnapitae 11
Band Name: Wahnapitae First Nation

Reserve Name: Walpole Island I.R. No.46
Band Name: Walpole Island First Nation

Reserve Name: West Bay I.R. No. 22
Band Name: West Bay First Nation

Reserve Name: Whitefish Bay I.R No. 32A
Band Name: Whitefish Bay First Nation

Reserve Name: Whitefish Bay I.R No. 34A and Lake of the Woods I.R No. 37
Band Name: Northwest Angle No. 37 First Nation

Reserve Name: Whitefish Lake I.R. No. 6
Band Name: Whitefish Lake First Nation

Reserve Name: Whitefish River I.R. No. 4
Band Name: Whitefish River First Nation

Reserve Name: Wikewemikong I.R. No. 26
Band Name: Wikwemikong Unceded First Nation

APPENDIX B

TAB 3 UNORGANIZED TOWNSHIPS

Networks provides service to numerous Unorganized geographic townships. These townships are not incorporated as municipalities.

APPENDIX B

TAB 4 MUNICIPALITIES IN WHICH A PORTION OF THE MUNICIPALITY IS SERVED BY THE LICENSEE AND ANOTHER PORTION OF THE MUNICIPALITY IS SERVED BY ANOTHER DISTRIBUTOR

Name of Municipality:	**Township of Alfred and Plantagenet**
Formerly Known As:	Township of Alfred, Village of Alfred, Township of North Plantagenet, Village of Plantagenet, as at December 31, 1996.
Area Not Served By Networks:	The area served by Hydro 2000 Inc. described as the former Villages of Alfred and Plantagenet as more particularly set out in Licence No. ED-2002-0542.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Amherstburg**
Formerly Known As:	Town of Amherstburg, Township of Anderdon, Township of Malden, as at December 31, 1997.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Amherstburg as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	Two industrial (former Direct Class) customers located at 381 Front Road North, Amherstburg ON, and 99 Thomas Road, Amherstburg ON

Name of Municipality:	**Township of Asphodel-Norwood**
Formerly Known As:	Township of Asphodel, Village of Norwood, as at December 31, 1997.
Area Not Served By Networks:	The area served by Peterborough Distribution Inc. described as the former Village of Norwood as more particularly set out in Licence No. ED-2002-0504.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Atikokan**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Atikokan Hydro Inc. as set out in Licence No. ED-2003-0001.
Networks assets within area not served by Networks:	No
Customer(s) within area not Served by Networks:	No

Name of Municipality:	**Town of Aylmer as at January 1, 1998.**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the Town of Aylmer as more particularly set out in Licence No. ED-2002-0156.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Belleville**
Formerly Known As:	City of Belleville, Township of Thurlow, City of Quinte West, as at December 31, 1997.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former City of Belleville as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township Blanford-Blenheim**
Formerly Known As:	Township Blanford-Blenheim as at March 31, 1999.
Area Not Served By Networks:	The area served by Cambridge and North Dumfries Hydro Inc. as particularly set out in Licence No. ED-2002-0574. The area served by Kitchener-Wilmot Hydro Inc. as particularly set out in Licence No. ED-2002-0573.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of the Blue Mountains**
Formerly Known As:	Town of Thornbury, Township of Collingwood, as at December 31**,** 1997.
Area Not Served By Networks:	The area served by COLLUS Power Corp. described as the former Town of Thornbury as more particularly set out in Licence No. ED-2002-0518.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Bluewater**
Formerly Known As:	Township of Hay, Township of Stanley, Village of Bayfield, Village of Hensall, Village of Zurich, as at December 31, 2000.
Area Not Served By Networks:	The area served by Festival Hydro Inc. described as the former Village of Hensall, and the former Village of Zurich as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Bracebridge**
Formerly Known As:	Townships of Macaulay, Draper, Monck, Oakely, Town of Bracebridge, as at December 31, 1970.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Town of Bracebridge, as more particularly set out in Licence No. ED-2002-0540.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One industrial customer located at 154 Beaumont Drive, Bracebridge, ON.

Name of Municipality:	**Town of Bradford-West Gwillimbury**
Formerly Known As:	Town of Bradford, Township of West Gwillimbury, as at December 31, 1990.
Area Not Served By Networks:	The area served by PowerStream Inc. as particularly set out in Licence No. ED-2004-0420, previously served by Barrie Hydro Distribution Inc. described as the former Town of Bradford as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**County of Brant (Initially known as City of Brant-on-the-Grand)**
Formerly Known As:	County of Brant, Town of Paris, Township of Brantford, Township of Burford, Township of Oakland, Township of Onondaga, Township of South Dumfries, as at December 31, 1998.
Area Not Served By Networks:	The area served by Brant County Power Inc. described as the former Village of Burford, the former Town of Paris, the former Township of Brantford and the former Police Village of St. George (in the former Township of South Dumfries) as more particularly set out in Licence No. ED-2002-0522. The area served by Cambridge and North Dumfries Hydro Inc. as particularly set out in Licence No. ED-2002-0574.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Brock**
Formerly Known As:	Village of Beaverton, Village of Cannington, Township of Brock, Township of Thorah, as at December 31, 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Villages of Beaverton and Cannington and the former Police Village of Sunderland (in the former Township of Brock) as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Brockton**
Formerly Known As:	Township of Greenock, Township of Brant, Town of Walkerton, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Walkerton and the portion of the former Police Village of Elmwood (in the former Township of Brant) as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Brooke-Alvinston**
Formerly Known As:	Township of Brooke, Village of Alvinston
Area Not Served By Networks:	The area served by Bluewater Power Distribution Corp. described as the former Village of Alvinston as more particularly set out in Licence No. ED-2002-0517.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Central Elgin**
Formerly Known As:	Township of Yarmouth, Village of Belmont, Village of Port Stanley, as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the former Villages of Belmont and Port Stanley as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Central Huron**
Formerly Known As:	Township of Goderich, Township of Hullett, Town of Clinton, as at December 31, 2000.
Area Not Served By Networks:	The area served by Clinton Power Corporation described as the former Town of Clinton as more particularly set out in Licence No. ED-2002-0496..

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Centre Wellington**
Formerly Known As:	Town of Fergus, Village of Elora, Township of West Garafraxa, Township of Nichol, Township of Pilkington, as at December 31, 1998.
Area Not Served By Networks:	The area served by Centre Wellington Hydro Ltd. described as the former Town of Fergus and the former Village of Elora as more particularly set out in Licence No. ED-2002-0498.
Networks Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Chatham-Kent**
Formerly Known As:	City of Chatham, County of Kent, Town of Blenheim, Town of Bothwell, Town of Dresden, Town of Ridgetown, Town of Tilbury, Town of Wallaceburg, Village of Erie Beach, Village of Erieau, Village of Highgate, Village of Thamesville, Village of Wheatley, Township of Camden, Township of Chatham, Township of Dover, Township of Harwich, Township of Howard, Township of Orford, Township of Raleigh, Township of Rodney, Township of Tilbury East, Township of Zone, as at December 31, 1997.
Area Not Served By Networks:	The area served by Chatham-Kent Hydro Inc. described as the former City of Chatham, former Police Village of Merlin (straddling the former townships of Raleigh and Tilbury East), former Village of Erieau, former Village of Thamesville, former Town of Bothwell, former Village of Wheatley, former Town of Dresden, former Town of Blenheim,

	former Town of Tilbury, former Town of Ridgetown, and the former Town of Wallaceburg as more particularly set out in Licence No. ED-2002-0563.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Clarington**
Formerly Known As:	Town of Bowmanville, Village of Newcastle, Township of Clarke, Township of Darlington, as at December 31, 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Bowmanville, the former Police Village of Orono (in the former Township of Clarke), the former Town of Newcastle as more particularly set out in Licence No. ED-2002-0503
N**etworks assets within area not served by Networks:**	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at 410 Waverley Road, Bowmanville ON.

Name of Municipality:	**Township of Clearview**
Formerly Known As:	Town of Stayner, Village of Creemore, Township of Nottawasaga, Township of Sunnidale, as at December 31, 1993.
Area Not Served By Networks:	The area served by COLLUS Power Corp. described as the former Town of Stayner and the former Village of Creemore as more particularly set out in Licence No. ED-2002-0518.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Cochrane**
Formerly Known As:	Town of Cochrane, Township of Glackmeyer, Unorganized Twp. of Lamarche, as at December 31, 1999.
Area Not Served By Networks:	The area served by Northern Ontario Wires Inc. described as the former Town of Cochrane as more particularly set out in Licence No. ED-2002-0018
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Cramahe**
Formerly Known As:	Village of Colborne, Township of Cramahe, as at December 31, 2000.
Area Not Served By Networks:	The area served by Lakefront Utilities Inc. described as the former Village of Colborne as more particularly set out in Licence No. ED-2002-0545.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Dutton/Dunwich**
Formerly Known As:	Township of Dunwich, Village of Dutton, as at December 31, 1997.
Area Not Served By Networks:	The area served by Dutton Hydro Limited described as the former Village of Dutton as more particularly set out in Licence No. ED-2003-0025.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of East Gwillimbury as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Newmarket-Tay Power Distribution Ltd. as particularly set out in Licence No. ED- 2007-0624.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of East Luther Grand Valley**
Formerly Known As:	Township of East Luther, Village of Grand Valley, as at December 31, 1994.
Area Not Served By Networks:	The area served by Orangeville Hydro Limited described as the former Village of Grand Valley as more particularly set out in Licence No. ED-2002-0500.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Township of East Zorra-Tavistock**
Formerly Known As:	Township of East Zorra, Town of Tavistock, as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Town of Tavistock as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Edwardsburgh/Cardinal**
Formerly Known As:	Village of Cardinal, Township of Edwardsburgh, as at December 31, 2000.
Area Not Served By Networks:	The area served by Rideau St. Lawrence Distribution Inc. described as the former Village of Cardinal as more particularly set out in Licence No. ED-2003-0003.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Essa as at March 31, 1999**.
Formerly Known As:	Same

Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as the former Police Village of Thorton as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Essex**
Formerly Known As:	Town of Essex, Town of Harrow, Township of North Colchester, Township of South Colchester, as at December 31, 1998.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as the former Town of Essex and the former Town of Harrow as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Gravenhurst**
Formerly Known As:	Formerly the Township of Morrison, the United Townships of Medora and Wood, the Township of Muskoka, the Township of Ryde, the Town of Gravenhurst, as at December 31, 1970.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former urban boundary of the Town of Gravenhurst as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No
Name of Municipality:	**City of Greater Sudbury**
Formerly Known As:	Region of Sudbury, City of Sudbury, City of Valley East, Town of Capreol, Town of Nickel Centre, Town of Onaping Falls, Town of Rayside-Balfour, Town of Walden, as at December 31, 2000.
Area Not Served By Networks:	The area served by Greater Sudbury Hydro Inc. described as the former City of Sudbury, the former townsite of the former Town of Capreol, and the former Town of Conniston (part of former Town of Nickel Centre) as more particularly set out in Licence No. ED-2002-0559.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of Guelph/Eramosa**
Formerly Known As:	Township of Guelph, Township of Eramosa, as at December 31, 1998.
Area Not Served By Networks:	The area served by Guelph Hydro Electric Systems Inc. as more particularly set out in Licence No. ED-2002-0565.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Hamilton**
Formerly Known As:	Region of Hamilton-Wentworth, City of Hamiton, City of Stoney Creek, Town of Ancaster, Town of Dundas, Town of Flamborough, Township of Glanbrook, as at December 31, 2000.
Area Not Served By Networks:	The area served by Horizon Utilities Corp. described as the former City of Hamilton, the former Police Village of Ancaster, former Town of Dundas, the former Police Village of Lynden (straddling the former Town of Flamborough and Town of Ancaster), the former Village of Waterdown, and the former City of Stoney Creek as more particularly set out in Licence No. ED-2006-0031.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Hawkesbury as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Hydro Hawkesbury Inc. described as the Town of Hawkesbury prior to annexation or amalgamation pursuant to the Minister's Order or Restructuring Act as more particularly set out in Licence No. ED-2003-0027.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Huntsville**
Formerly Known As:	Township of Brunel, Village of Port Sydney, Town of Chaffey, Township of Stephenson, Township of of Stisted, Town of Huntsville, as at December 31, 1970.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Town of Huntsville as more particularly set out in Licence No. ED-2002-0540.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at 61 Domtar Road, Huntsville ON.

Name of Municipality:	**Municipality of Huron East**
Formerly Known As:	Village of Brussels, Township of Grey, Township of McKillop, Town of Seaforth, Township of Tuckersmith, as at December 31, 2000.
Area Not Served By Networks:	The area served by Festival Hydro Inc. described as the former Village of Brussels and the former Town of Seaforth as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Huron-Kinloss**
Formerly Known As:	Township of Huron (former Police Village of Ripley amalgamated with twp in 1995), Township of Kinloss, Village of Lucknow, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former

	Police Village of Ripley (in the former Township of Huron) and the former Village of Lucknow as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Huron Shores**
Formerly Known As:	Township of Day & Bright Add'l, Township of Thessalon, Township of Thompson, Village of Iron Bridge, as at December 31, 1998.
Area Not Served By Networks:	The area served by Great Lakes Power Limited described as part of the former Township of Thessalon or as more particularly set out in Licence No. ED-1999-0227
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Ingersoll**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the Town of Ingersoll as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No
Name of Municipality:	**Town of Iroquois Falls as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Northern Ontario Wires Inc. described as the Town of Iroquois Falls as more particularly set out in Licence No. ED-2002-0018.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**City of Kenora**
Formerly Known As:	Town of Kenora, Town of Keewatin, Town of Jaffray Melick, as at December 31,1999.
Area Not Served By Networks:	The area served by Kenora Hydro Electric Corporation Ltd. described as the former Town of Kenora and part of the former Town of Keewatin as more particularly set out in Licence No. ED-2003-0030.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of Killaloe, Hagarty and Richards**
Formerly Known As:	Township of Hagarty and Richards, Village of Killaloe, as at June 30, 1999

Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Village of Killaloe as more particularly set out in Licence No. ED-2002-0033.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Kincardine**
Formerly Known As:	Town of Kincardine, Township of Bruce (Village of Tiverton, Township of Bruce amalgamation), Township of Kincardine, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Kincardine as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of King as at March 31, 1999**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by PowerStream Inc. as more particularly set out in Licence No. ED-2004-0420. The area served by Newmarket-Tay Power Distribution Ltd. as more particularly set out in Licence No. ED-2007-0624.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not Served by Networks:	No

Name of Municipality:	**City of Kingston**
Formerly Known As:	City of Kingston, Township of Kingston, Township of Pittsburgh, as at December 31, December 31, 1997.
Area Not Served By Networks:	The area served by Kingston Electricity Distribution Ltd. described as the former City of Kingston, the former Township of Kingston, and part of the former Township of Pittsburgh as more particularly set out in Licence No. ED-2003-0057. The area served by Canadian Niagara Power Inc. described as part of the former Township of Pittsburgh as more particularly set out in Licence No. ED-2002-0572.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Kingsville**
Formerly Known As:	Town of Kingsville, Township of Gosfield North, Township of Gosfield South, as at December 31, 1997.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as the former Town of Kingsville and the former Police Village of Cottam (in the former Township of Gosfield North), including Part Lot 269 Part 1 12R-23403, Part Lot 268 Part 1 12R-23674 and Part Lot 269RP 12R-1331 Parts 4

	and 5 located at 168 Belle River Road North, as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Lakeshore**
Formerly Known As:	Township of Lakeshore, (Jan 1998: Town of Belle River, Township of Maidstone amalgamated into Lakeshore Township), Township of Rochester, Township of Tillbury North, Township of Tillbury West, as at December 31, 1998.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as the former Police Village of Comber (in the former Township of Tillbury West) and the former Town of Belle River as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Leamington**
Formerly Known As:	Town of Leamington, Township of Mersea, as at December 31, 1998.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Leamington as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of Leeds and the Thousand Islands**
Formerly Known As:	Township of Front of Leeds and Lansdowne, Township of Rear of Leeds and Lansdowne, Township of Front of Escott, as at December 31, 2000.
Area Not Served By Networks:	The area served by Canadian Niagara Power Inc. described as part of the former Township of the Front of Leeds and Lansdowne as more particularly set out in Licence No. ED-2002-0572.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Municipality of Magnetawan**
Formerly Known As:	Township of Chapman, Village of Magnetawan, Unorganized Township of Croft, as at December 31, 1997.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Village of Magnetawan as more particularly set out in Licence No. ED-2002-0540.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Minto**
Formerly Known As:	Township of Minto, Town of Palmerston, Town of Harriston, Village of Clifford, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Harriston, the former Town of Palmerston, and the former Village of Clifford as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Corporation of the Town of Mississippi Mills**
Formerly Known As:	Town of Almonte, Township of Pakenham, Township of Ramsay, as at December 31, 1998.
Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Town of Almonte as more particularly set out in Licence No. ED-2003-0033.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of New Tecumseth**
Formerly Known As:	Town of Alliston, the Village of Beeton, the Village of Tottenham and the portion of the Township of Tecumseth, as at December 31, 1991.
Area Not Served By Networks:	The area served by PowerStream Inc. described as the former Town of Alliston, the former Village of Beeton and the former Village of

	Tottenham (all in the former Township of Tecumseth) as more particularly set out in Licence No. ED-2004-0420.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located in the former Town of Alliston.
Name of Municipality:	**The Corporation of Norfolk County**
Formerly Known As:	Township of Norfolk, Township of Delhi, Town of Simcoe, City of Nanticoke (westerly 'half' only), as at December 31, 2000.
Area Not Served By Networks:	The area served by Norfolk Power Distribution Inc. described as the former Town of Delhi (in the former Township of Delhi), the westerly half of the former City of Nanticoke, the former Village of Port Rowan (in former Township of Norfolk), and the former Town of Simcoe as more particularly set out in Licence No. ED-2002-0521.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at Lake Erie and Regional Rd.. 3, Nanticoke, ON.
Name of Municipality:	**Township of North Huron**
Formerly Known As:	Town of Wingham, Village of Blyth, Township of East Wawanosh,as at December 31, 2000.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Wingham as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	Two Industrial customers located at 40621 Amberly Rd., and 200 Water Street Wingham, ON.

Name of Municipality:	**Municipality of North Middlesex**
Formerly Known As:	Township of McGillivray, Township of East Williams, Township of West Williams, Town of Parkhill, Village of Ailsa Craig, as at December 31, 2000.
Area Not Served By Networks:	The area served by Middlesex Power Distribution Corp. described as the former Town of Parkhill as more particularly set out in Licence No. ED-2003-0059.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Township of Norwich as at March 31, 1999**.
Formerly Known As:	Township of North Norwich, Township of South Norwich, Township of East Oxford, Village of Norwich, Village of Burgessville, and Police Village of Otterville, as at
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Norwich, the former Village of Burgessville, and the former Police Village of Otterville as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Ottawa**
Formerly Known As:	Region of Ottawa-Carleton, City of Gloucester, City of Kanata, City of Nepean, City of Ottawa, City of Vanier, Township of Cumberland, Township of Goulbourn, Township of Osgoode, Township of Rideau, Township of West Carleton, Village of Rockcliffe Park, as at December 31, 2000.
Area Not Served By Networks:	The area served by Hydro Ottawa Limited described as the former City of Gloucester, the former City of Kanata, the former City of Nepean, the former City of Ottawa, the former City of Vanier, the former Township of Goulbourn, the former Village of Rockcliffe Park, and the portion of the former Township of Rideau on Long Island, North of Bridge Street, as more particularly set out in Licence No. ED-2002-0556.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No.

Name of Municipality:	**Town of Pelham**
Formerly Known As:	Township of Pelham, Village of Fonthill, as at December 31, 1969.
Area Not Served By Networks:	The area served by Niagara Peninsula Energy Inc.described as the former Village of Fonthill as more particularly set out in Licence No. ED-2002-0555.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Perth East**
Formerly Known As:	Township of Mornington, Township of Ellice, Township of North Easthope, Township of South Easthope, Village of Milverton, as at December 31, 1997.
Area Not Served By Networks:	The area served by Festival Hydro Inc. as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Peterborough as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Peterborough Distribution Inc. described as the City of Peterborough as more particularly set out in Licence No. ED-2002-0504.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Port Hope**
Formerly Known As:	Town of Port Hope, Township of Hope (initially restructured as Municipality of Port Hope and Hope), as at December 31, 2000.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Port Hope as more particularly set out in Licence No. ED-

	2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Puslinch as at March 31, 1999**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Guelph Hydro Electric Systems Inc. as more particularly set out in Licence No. ED-2002-0565.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Red Lake**
Formerly Known As:	Township of Red Lake, Township of Golden, as at June 30, 1997.
Area Not Served By Networks:	The area served by Gold Corp Inc. described as part of the former Improvement District of Balmertown.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Russell as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Cooperative Hydro Embrun Inc. described as the

	former Police Village of Embrum as more particularly set out in Licence No. ED-2002-0493.
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Sables-Spanish Rivers**
Formerly Known As:	Town of Massey, Town of Webbwood, Township of the Spanish River, as at June 30, 1997.
Area Not Served By Networks:	The area served by Espanola Regional Hydro Distribution Corp. described as the former Town of Massey and the former Town of Webbwood as more particularly set out in Licence No. ED-2002-0502.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Saugeen Shores**
Formerly Known As:	Township of Saugeen, Town of Southampton, Town of Port Elgin, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Southampton and the former Town of Port Elgin as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not	

served by Networks:	No
Name of Municipality:	**City of St. Thomas as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by St. Thomas Energy Inc. described as the City of St. Thomas as more particularly set out in Licence No. ED-2002-0523.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at 1 Cosma Court
Name of Municipality:	**Township of Scugog**
Formerly Known As:	Township of Scugog, Township of Cartwright, Township of Reach, Village of Port Perry, as at December 31. 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Village of Port Perry as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Municipality of Sioux Lookout**
Formerly Known As:	Town of Sioux Lookout, as at December 31, 1997
Area Not Served By Networks:	The area served by Sioux Lookout Hydro Inc. described as the Municipality of Sioux Lookout as more particularly set out in Licence No. ED-2002-0514.
Networks assets within area	

not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Smith-Ennismore-Lakefield**
Formerly Known As:	Village of Lakefield, Township of Smith-Ennismore (formerly Township of Smith and Township of Ennismore), as at December 31, 2000.
Area Not Served By Networks:	The area served by Peterborough Distribution Inc. described as the former Village of Lakefield as more particularly set out in Licence No. ED-2002-0504.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of South Bruce**
Formerly Known As:	Township of Mildmay-Carrick, Township of Teeswater-Culross, (Jan 1998: Village of Teeswater, Township of Culross amalgamated into the Township of Teeswater-Culross. Village of Mildmay, Township of Carrick amalgamated into the Township of Mildmay-Carrick), as at December 31, 1997.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Village of Mildmay and the former Village of Teeswater as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of South Dundas**
Formerly Known As:	Township of Matilda, Township of Williamsburg, Village of Iroquois, Village of Morrisburg, as at December 31, 1997.
Area Not Served By Networks:	The area served by Rideau St. Lawrence Distribution Inc. described as the former Police Village of Williamsburg, the former Village of Morrisburg, and the former Village of Iroquois as more particularly set out in Licence No. ED-2003-0003.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of South Glengarry**
Formerly Known As:	Township of Charlottenburgh, Township of Lancaster, Village of Lancaster, Police Village of Martintown, as at December 31, 1997.
Area Not Served By Networks:	The area served by the Cornwall Street Railway Light and Power Company Limited described as part of the former Township of Charlottenburgh as more particularly set out in Licence No. ED-2004-0405.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	**Three Solar PV generator customers located at:** 1. Part of Lots 5 & 6, Concession 5 2. Part of Lots 15 & 16, Concession 5 & 6 3. Lot 41, 41A, Plan 107 except Part 20 and 20A on 14R299, s/t IL 3007, TCH 4416 and Plan 107 – Pt Lot 40 as in AR 1461, Except Pt 1 & 2, 14R2143 S/T TCH 4357

Name of Municipality:	**Municipality of South Huron**
Formerly Known As:	Township of Stephen, Township of Usborne, Town of Exeter, as at

	December 31, 2000.
Area Not Served By Networks:	The area served by Festival Hydro Inc. described as the former Police Village of Dashwood as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of South Stormont**
Formerly Known As:	Township of Osnabruck, Township of Cornwall, as at December 31, 1997
Area Not Served By Networks:	The area served by Cornwall Street Railway Light and Power Company Limited described as part of the former Township of Cornwall and part of the former Township of Osnabruk as more particularly set out in Licence No. ED-2004-0405.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Southgate**
Formerly Known As:	Village of Dundalk, Township of Egremont, Township of Proton, Police Village of Holstein, as at December 31, 1999.
Area Not Served By Networks:	The area served by Wellington North Power Inc. described as the former Police Village of Holstein as more particularly set out in Licence No. ED-2002-0511.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Township of South-West Oxford**
Formerly Known As:	Township of West Oxford, Township of Dereham, Village of Beachville, as at December 31,. 1974.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Beachville as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Stratford**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Festival Hydro Inc. as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Strathroy-Caradoc**
Formerly Known As:	Town of Strathroy, Township of Caradoc**,** as at December 31, 2000.
Area Not Served By Networks:	The area served by Middlesex Power Distribution Corp. described as the former Police Village of Mount Brydges (in the former Township of Caradoc) and the former Town of Strathroy as more particularly set out in Licence No. ED-2003-0059.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Tay**
Formerly Known As:	Village of Port NcNicoll, Village of Victoria Harbour, the Township of Medonte, Township of Tay, Township of Tiny, Township of Flos, Police Village of Waubaushene, as at December 31, 1996.
Area Not Served By Networks:	The area served by Newmarket-Tay Power Distribution Ltd. as more particularly set out in Licence No. ED-2007-0624.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Tecumseh**
Formerly Known As:	Town of Tecumseh, Village of St. Clair Beach, Township of Sandwich South, as at December 31, 1998.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Tecumseh and the former Village of St. Clair Beach as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Uxbridge**
Formerly Known As:	Town of Uxbridge, Township of Scott, Township of Uxbridge, as at December 31. 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Uxbridge as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Warwick**
Formerly Known As:	Village of Watford, Township of Warwick, as at December 31, 1997.
Area Not Served By Networks:	The area served by Bluewater Power Distribution Corp. described as the former Village of Watford as more particularly set out in Licence No. ED-2002-0517.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Wellington North**
Formerly Known As:	Town of Mount Forest, Village of Arthur, Township of Arthur, Township of West Luther, as at December 31, 1998.
Area Not Served By Networks:	The area served by Wellington North Power Inc. described as the former Village of Arthur and the former Town of Mount Forest as more particularly set out in Licence No. ED-2002-0511.

Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of West Grey**
Formerly Known As:	Township of West Grey, Town of Durham (Jan 2000 Township Bentinck, Township of Glenelg, Town Normanby, Village of Neustadt amalgamated into the Township of West Grey), as at December 31, 1999.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Village of Neustadt and a portion of the former Police Village of Elmwood (in the former Township of Bentinck) as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of West Nipissing**
Formerly Known As:	Town of Cache Bay, Town of Sturgeon Falls, Township of Caldwell, Township of Field, Township of Springer, as at December 31, 1998.
Area Not Served By Networks:	The area served by West Nipissing Energy Services Ltd. described as the former Town of Cache Bay and the former Town of Sturgeon Falls as more particularly set out in Licence No. ED-2002-0562.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of West Perth**
Formerly Known As:	Township of Logan, Township of Fullarton, Township of Hibbert, Town of Mitchell, Police Village of Dublin, as at December 31, 1997.
Area Not Served By Networks:	The area served by West Perth Power Inc. described as the former Town of Mitchell and the former Police Village of Dublin as more particularly set out in Licence No. ED-2002-0508.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Whitby**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Whitby Hydro Electric Corporation and the area served by Veridian Connections Inc. as more particularly set out in Licence No. ED-2002-0571.

Name of Municipality:	**Township of Whitewater Region**
Formerly Known As:	Township of Ross, Township of Westmeath, Village of Beachburg, Village of Cobden, as at December 31, 2000.
Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Village of Beachburg as more particularly set out in Licence No. ED-2003-0033.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Woodstock as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Woodstock Hydro Services Inc. described as the City of Woodstock as more particularly set out in Licence No. ED-

	2003-0011, including the Boot Hill Development located on part of lots 3, 7, 8, 11, 12, 13 and registered plan 86 and 501, and three customers on Mill Street with civic address numbers 388, 390 and 410.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Zorra**
Formerly Known As:	Township of West Zorra, Township of East Nissouri, Township of North Oxford, Village of Embro, Village of Thamesford , as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Embro and the former Village of Thamesford as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Town of Penetanguishene as at March 31, 1999**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as part of the Town of Penetanguishene as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

APPENDIX B

TAB 5 CONSUMERS EMBEDDED WITHIN ANOTHER DISTRIBUTOR BUT SERVED BY THE LICENSEE

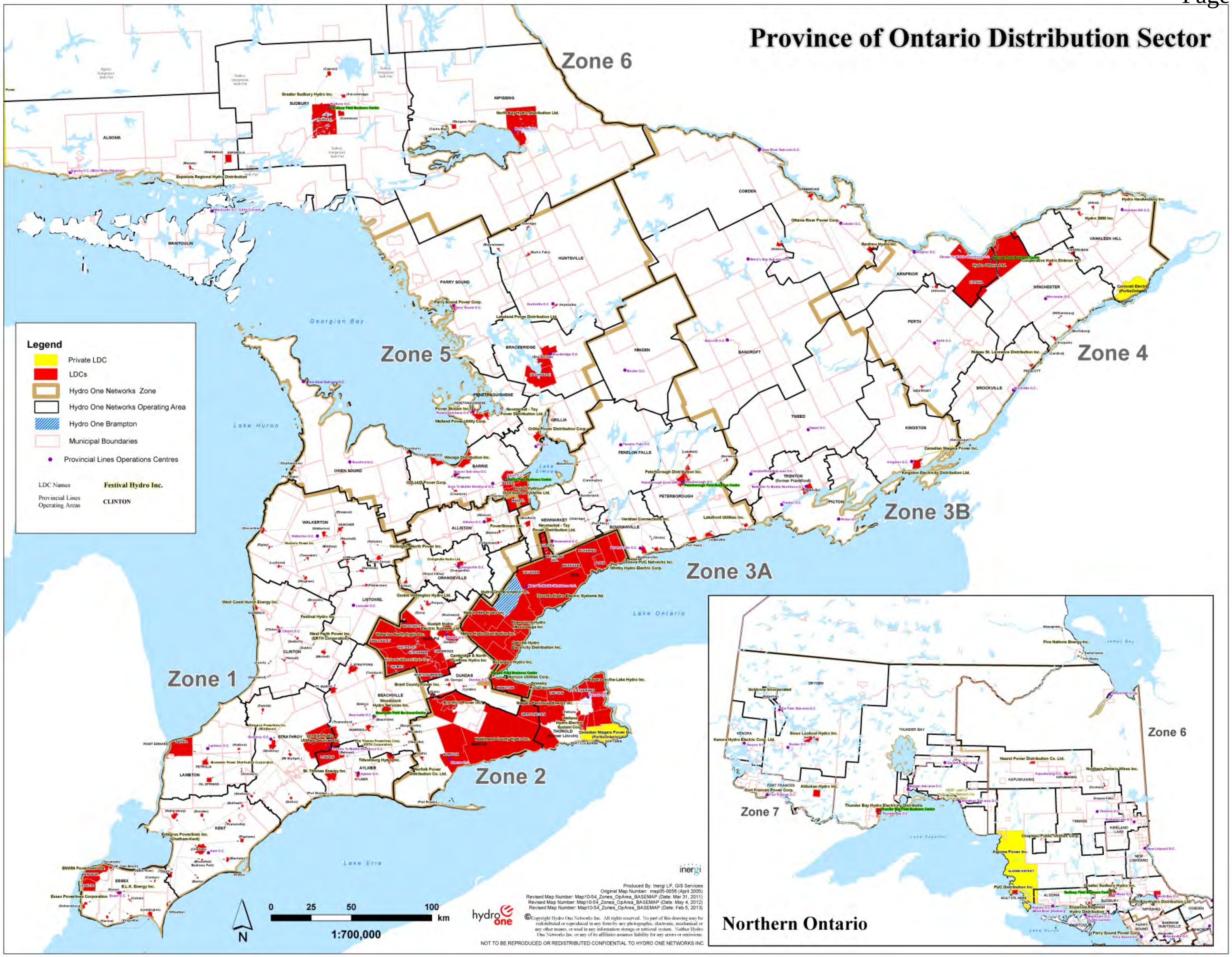
(Note also that each municipality noted in Tab 5 is a municipality served almost entirely by another distributor but in which the Licensee serves one or more consumers.)

Name of Municipality:	**City of Cornwall**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	The customers located at 501 Wallrich Avenue.

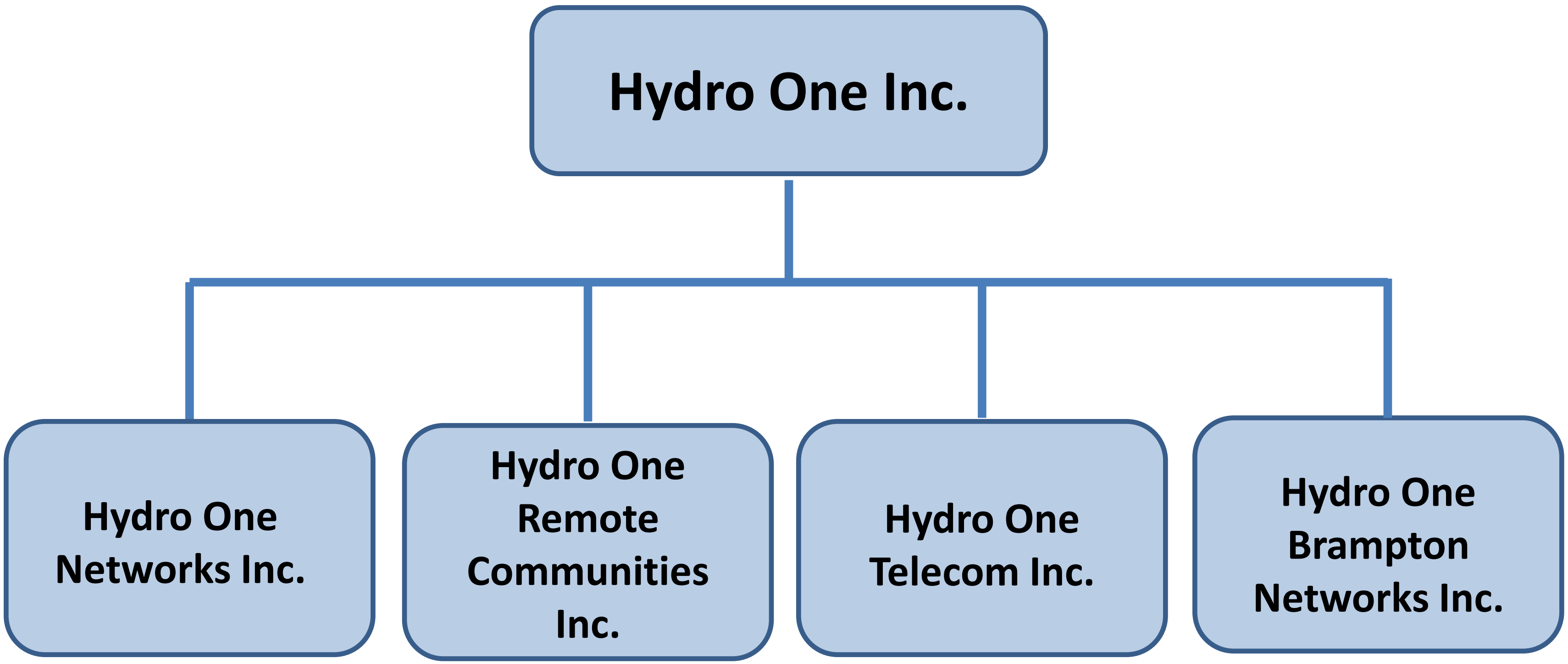
Name of Municipality:	**County of Haldimand**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One customer located in Caledonia, Ont.

Name of Municipality:	**City of Niagara Falls**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	Three customers located at 8001 Daly Street, 7780 Stanley Ave, 6225 Progress Street

Name of Municipality:	**City of St. Thomas**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One industrial customer located at 1 Cosma Court.

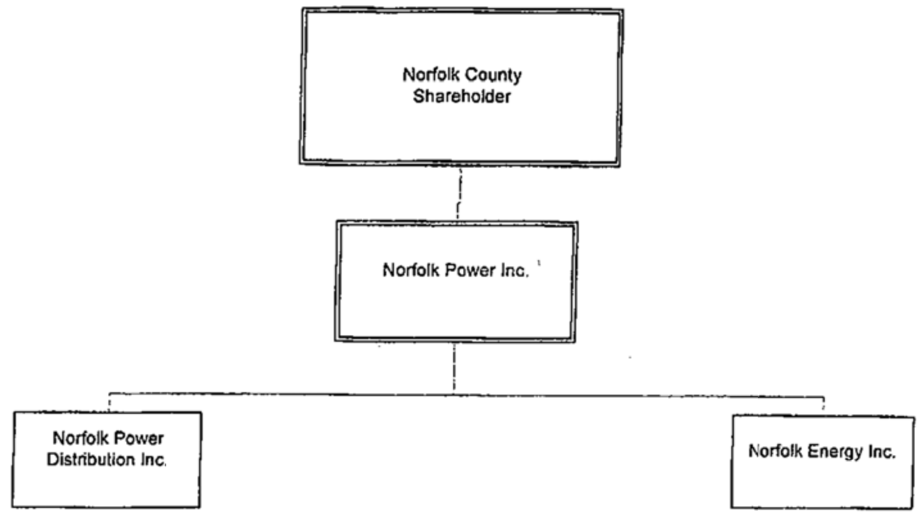

Province of Ontario Distribution Sector
Zone 6
Zone 5
Zone 4
Zone 3B
Zone 3A
Zone 2
Zone 1
Georgian Bay
Lake Huron
Lake Ontario
Lake Erie
Legend
Private LDC
LDCs
Hydro One Networks Zone
Hydro One Networks Operating Area
Hydro One Brampton
Municipal Boundaries
Provincial Lines Operations Centres
LDC Names
Festival Hydro Inc.
Provincial Lines Operating Areas
CLINTON
N
0
25
50
100
km
1:700,000
hydro one
inergi
Northern Ontario
Zone 6
Zone 7
NOT TO BE REPRODUCED OR REDISTRIBUTED CONFIDENTIAL TO HYDRO ONE NETWORKS INC

Hydro One Inc. Corporate Structure

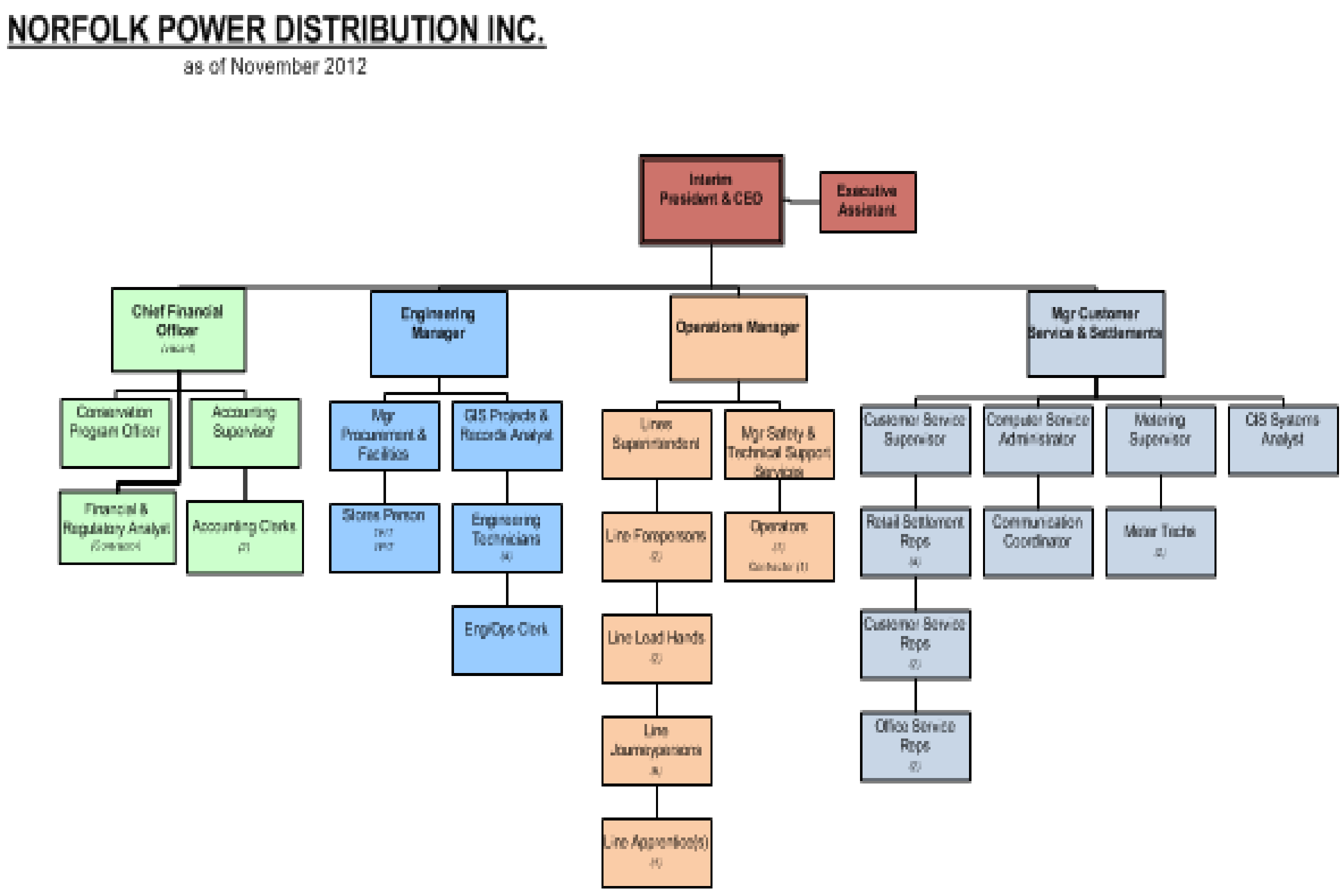


Attachment 5

The Corporation of Norfolk County – Organization Chart



NPDI Organizational Chart



THE CORPORATION OF NORFOLK COUNTY

- and -

HYDRO ONE INC.

SHARE PURCHASE AGREEMENT

Dated the 2nd day of April, 2013

Borden Ladner Gervais LLP
Scotia Plaza
40 King Street West
Toronto, Ontario
M5H 3Y4

SHARE PURCHASE AGREEMENT

THIS AGREEMENT made the 2nd day of April, 2013 (the "Effective Date").

B E T W E E N:

THE CORPORATION OF NORFOLK COUNTY, a municipal corporation under the laws of Ontario, (the "**Vendor**")

\- and -

HYDRO ONE INC., a corporation incorporated under the laws of Ontario, (the "**Purchaser**")

WHEREAS Norfolk Power Inc. (the "Corporation") is a corporation incorporated under the *Business Corporations Act* (Ontario) and is wholly-owned by the Vendor;

AND WHEREAS the Vendor is the beneficial and registered owner of all of the issued and outstanding shares of the Corporation;

AND WHEREAS the Vendor wishes to sell to the Purchaser, and the Purchaser wishes to purchase from the Vendor, all of the issued and outstanding shares of the Corporation, on and subject to the terms and conditions set forth herein;

THIS AGREEMENT WITNESSES THAT in consideration of the respective covenants, agreements, representations and warranties of the Parties herein contained and for other good and valuable consideration (the receipt and sufficiency of which are acknowledged by each Party), the Parties covenant and agree as follows.

ARTICLE I
INTERPRETATION

1.1 **Defined Terms.** In this Agreement, including the recitals, and schedules hereto, unless the context otherwise specifies or requires, the following terms shall have the respective meanings specified or referred to below and grammatical variations of such terms shall have corresponding meanings:

(a) "**Affiliate**" has the meaning ascribed thereto in the OBCA.

(b) "**Agreement**" means this share purchase agreement, including all schedules attached hereto, as amended, supplemented, restated and replaced from time to time in accordance with its provisions.

(c) "**Ancillary Agreement**" has the meaning set forth in Section 6.9.

(d) "**Applicable Law**" means any and all applicable laws, including Environmental Laws, common law, statutes, codes, licensing requirements, directives, rules, regulations, protocols, policies, by-laws, guidelines, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any Government Authority, including without limitation, the OEB.

(e) "**Auditors**" means Millard, Rouse & Rosebrugh LLP, Chartered Accountants.

(f) "**Business**" means, the business carried on by the Norfolk Corporations including the distribution of electricity, and the provision of Dark Fibre Rental Services in Norfolk County.

(g) "**Business Day**" means a day other than a Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto are not open for business during normal banking hours.

(h) "**Claim**" means:

(i) any act, omission or state of facts actionable under or contrary to Applicable Law (including for clarity and without limitation, in contract, tort or equity); and

(ii) any loss, liability, damage or expense arising in connection with

(A) remediation of Environmental matters,

(B) litigation or matter disclosed in Schedule 3.1(u),

(C) terms of any Contracts to the extent the terms or Contracts were not included in the Data Room prior to the Proposal Date, other than written terms of employment contracts true copies of which have been provided to the Purchaser,

(D) resolution of matters relating to Employees and former Employees,

(E) Encumbrances on any of the assets of the Norfolk Corporations other than those excluded in Section 3.1(x), and listed in Schedule 3.1(x),

and in either case arising prior to Closing, whether or not known to the Vendor or the Purchaser, and any demand, action, investigation, inquiry, suit, proceeding, claim, assessment, judgment or settlement or compromise relating thereto.

(i) "**Closing**" means completion of the Transactions contemplated herein on the Closing Date and in accordance with the provisions of this Agreement.

(j) "**Closing Date**" means a date (which shall be a Business Day) not later than thirty (30) days following the date that the Required Approval has been obtained or such earlier or later date as may be agreed to by the Parties in writing provided that in no event shall any such date be on or after December 31, 2014.

(k) "**Closing Date Financial Statements**" means consolidated audited financial statements for the Corporation for the fiscal period ended on the Closing Date, prepared in accordance with GAAP, on the same basis as the Financial Statements, consistently applied and consisting of a balance sheet as of such date and statements of operations, retained earnings, and cashflow for such period, together with notes thereto as at such date of the Corporation's auditors thereon addressed to the Corporation.

(l) "**Closing Date NFA**" means the amount of NFA stated on the Closing Date Financial Statements.

(m) "**Closing Date Working Capital**" shall have the meaning ascribed thereto in Section 2.4(a)(i).

(n) "**Change in Applicable Law**" means:

(i) the enactment, introduction or tabling of any Canadian federal or provincial legislation (whether by statute, regulation, order-in-council, notice of ways and means motion or otherwise);

(ii) a ruling, order or decision of the OEB, including a ruling, order or decision of the OEB, relating to an electricity distribution utility other than the utility operated by NPDI;

(iii) the issuance, modification or revision of the OEB's existing Electricity Distribution Rate Handbook, or the issuance of any rule, procedure, code, policy or directive by the OEB; and

(iv) a directive, guideline or policy statement of a Government Authority;

taking effect after the Execution Date.

(o) "**Collective Agreement**" has the meaning ascribed thereto in Section 3.1(q)(i).

(p) "**Common Shares**" means the common shares in the share capital of the Corporation.

(q) "**Confidentiality Agreement**" means the confidentiality agreement between the Corporation, and the Purchaser dated December 10th, 2012.

(r) "**Confidential Information**" has the meaning ascribed thereto in Subsection 6.10(b)(i).

(s) "**Corporation**" means Norfolk Power Inc.

(t) "**Contract**" means any agreement, indenture, contract, lease, deed of trust, licence, option, instrument or other commitment, whether written or oral.

(u) "**CTA**" means the *Corporations Tax Act* (Ontario) or the *Taxation Act, 2007* (Ontario) and any regulation made thereunder.

(v) "**Current Rates**" means those Rates specified in the Rate Order, and as presented under the column entitled "2013" in Schedule 6.7 of this Agreement.

(w) "**Daily Distribution Service Revenues**" means a revenue value equal to thirty three thousand one hundred and eleven dollars ($33,111).

(x) "**Damages**" means any loss, liability, damage or expense (including reasonable legal fees, accountants', investigators', engineers' and consultants' fees and expenses, interest, penalties and amounts paid in settlements), whether resulting from any action, suit, proceeding, arbitration, claim or demand that is instituted or asserted by a third party, or any cause, matter, thing, act or omission or state of facts not involving a third party, but excluding any incidental, indirect or consequential loss, liability or damage and loss of profits other than damages of a third party in respect of a Third Party Claim.

(y) "**Dark Fibre Rental Services**" means the provision of dark fibre pairs for purposes of high speed communication links to remote equipment and substations.

(z) "**Data Room**" means the NPDI and NEI data sites located at https://extranet.blg.com/clients/norfolkpowerdistribution/ and https://extranet.blg.com/clients/norfolkenergy/ , respectively.

(aa) "**Decision Period Days**" means the number of days between the Closing Date and the Reduced Rates Effective Date.

(bb) "**Decision Period Payment Amount**" means an amount equal to thirty three thousand one hundred and eleven dollars ($33,111) times Decision Period Days times one percent (1%) times the Decision Period Payment Factor.

(cc) "**Decision Period Payment Factor**" means a factor equal to one (1) minus the Rate Adjustment Factor.

(dd) "**Deposit**" has the meaning given to it in Section 2.3(a).

(ee) "**Direct Claim**" has the meaning ascribed thereto in Section 12.3.

(ff) "**Distribution Services Revenues**" means the revenues referred to as "distribution services revenues" in the statement of operations of the Corporation.

(gg) "**Draft Financial Statements**" means those draft unaudited financial statements as provided to the Purchaser on March 27, 2013, copies of which are attached as Schedule

1.1(gg) hereto related to the Norfolk Corporations as provided by the Vendor to the Purchaser prior to the Effective Date.

(hh) "**Easements**" means the right in perpetuity to use, traverse, enjoy or have access to, over, in or under any real property.

(ii) "**EA**" means the *Electricity Act, 1998* (Ontario), as amended from time to time..

(jj) "**Effective Date**" means the date of this Agreement as first stated above.

(kk) "**Employee Plans**" has the meaning attributed to that term in Section 3.1(p)(i).

(ll) "**Employees**" has the meaning ascribed thereto in Section 3.1(r)(i).

(mm) "**Employee Fact Sheet**" has the meaning ascribed thereto in Section 3.1(r)(i).

(nn) "**Encumbrance**" means any encumbrance, lien, charge, hypothec, pledge, mortgage, title retention agreement, security interest of any nature, adverse claim, exception, reservation, easement, right of occupation, any matter capable of registration against title, option, right of pre-emption, privilege or any Contract to create any of the foregoing.

(oo) "**Environment**" means the environment or natural environment as defined in any Environmental Law and includes air, surface water, ground water, land surface, soil, sub-surface strata and sewer system.

(pp) "**Environmental Approvals**" means all permits, certificates, licences, authorizations, consents, registrations, directions, instructions, waste generation numbers or approvals required pursuant to Environmental Laws with respect to Real Property or the operation of any of the Norfolk Corporations or their respective Business.

(qq) "**Environmental Laws**" means all Applicable Law relating in whole or in part to the protection of the Environment or to public health and safety, and includes those relating to the manufacture, processing, distribution, use, treatment, storage, disposal, discharge, transportation or handling of Hazardous Substances.

(rr) "**Escrow Agreement**" means the form of escrow agreement attached hereto as Schedule 2.3.

(ss) "**ETA**" means Part IX of the *Excise Tax Act* (Canada) and any regulation made thereunder.

(tt) "**Financial Statements**" means the consolidated audited financial statements of the Corporation as at December 31, 2012 prepared in accordance with GAAP.

(uu) "**Five-Year Fixed Payment Amount**" means an amount equal to four hundred ninety thousand dollars ($490,000) times the Rate Adjustment Factor.

(vv) "**Fixed Assets**" means fixed assets, furniture, furnishings, parts, tools, personal property fixtures, plants, buildings, structures, erections, improvements, appurtenances, machinery, equipment, computer hardware and software, substations, transformers, vaults, distribution lines, transmission lines, conduits, ducts, pipes, wires, rods, cables, fibre optic strands, devices, appliances, material, poles, pipelines, fittings and any other similar or related item of a Norfolk Corporation's Business.

(ww) "**GAAP**" means the generally accepted accounting principles (including the methods of application of such principles) accepted or recommended by the Canadian Institute of Chartered Accountants which are applicable in Canada as at the date on which any calculation made hereunder is to be effective.

(xx) "**Governmental Authority**" means any domestic or foreign government, whether federal, provincial, state, territorial, local, regional, municipal, or other political jurisdiction, and any agency, authority, instrumentality, court, tribunal, board, commission, bureau, arbitrator, arbitration tribunal or other tribunal, or any quasi-governmental or other entity, insofar as it exercises a legislative, judicial, regulatory, administrative, expropriation or taxing power or function of or pertaining to government.

(yy) "**Hazardous Substances**" means any hazardous substance or any pollutant or contaminant, toxic or dangerous waste, substance or material as defined in or regulated by any Environmental Law including, without limitation, friable asbestos and poly-chlorinated biphenyls.

(zz) "**Indemnified Party**" has the meaning ascribed thereto in Section 12.3.

(aaa) "**Indemnifying Party**" has the meaning ascribed thereto in Section 12.3.

(bbb) "**Independent Auditor**" has the meaning ascribed thereto in Section 2.4(d).

(ccc) "**Initial Long Term Debt**" means an amount of long term debt equal to twenty-six million, nine hundred and ninety-seven thousand, four hundred and fifty-seven dollars ($26,997,457).

(ddd) "**Leased Property**" has the meaning ascribed thereto in Subsection 3.1(k).

(eee) "**Licenses**" has the meaning ascribed thereto in Subsection 3.1(z).

(fff) "**Long Term Debt**" means long term debt as defined in the Corporation's Financial Statements prepared as at the Closing Date. For greater certainty, Long Term Debt excludes the current portion of long term debt.

(ggg) "**Long Term Debt Calculation**" has the meaning ascribed thereto in Section 2.4(a)(iii).

(hhh) "**Losses**" means any and all loss, liability, damage, cost, expense, charge, fine, penalty or assessment, suffered or incurred by the Person seeking indemnification, directly resulting from or arising out of any Claim, including the costs and expenses of any action, suit, proceeding, investigation, inquiry, arbitration award, grievance, demand, assessment, judgment, settlement or compromise relating thereto,[including without limitation a gross-up to account for any tax payable or a reduction in the "cost amount", as defined in subsection 248(1) of the *Income Tax Act* (Canada) of any property owned by the Purchaser or a successor entity in the taxation year as a result of receiving the indemnification amount but: (i) excluding any contingent liability until it becomes actual; (ii) reduced by any net Tax benefit; and (iii) reduced by any recovery, settlement or otherwise under or pursuant to any insurance coverage, or pursuant to any claim, recovery, settlement or payment by or against any other Persons.

(iii) "**Material Adverse Effect**" means any change or effect that has a material adverse effect on the Property or obligations and liabilities of any of the Norfolk Corporations or the operations or results of operations of the Business any of the Norfolk Corporations after taking into account any insurance which may be available with respect to such a change or effect. For greater clarity, a Material Adverse Effect does not include a Change in Law.

(jjj) "**Material Contract**" means any Contract for the supply of goods or services which has a value exceeding Fifty Thousand Dollars ($50,000.00) in annual payments excluding any collective bargaining agreements or other employment related agreements.

(kkk) "**Material Discrepancies**" means the difference greater than ten percent (10%) between the amounts recorded on the Draft Financial Statements with respect to Regulatory Assets, Regulatory Liabilities, Post-Employment Benefits and Customer Deposits (the "Line Items") and the amount of these Line Items recorded on the Financial Statements, but shall exclude any and all Taxes including Future Income Tax, any amounts attributable to events occurring after December 31, 2012, and any and all adjustments provided for in Section 2.4 of this Agreement.

(lll) "**Negative Rate Rider**" has the meaning ascribed thereto in Section 6.7(a)(i) of this Agreement.

(mmm) "**NEI**" means Norfolk Energy Inc., a corporation incorporated under the OBCA, carrying on the business of dark fibre services in the service territory of Norfolk County, and a wholly-owned subsidiary of the Corporation.

(nnn) "**NFA**" means the aggregate value of the Corporation's property and equipment as provided in its financial statements.

(ooo) "**NFA Calculation**" has the meaning set out in Section 2.4(a)(ii).

(ppp) "**NFA Index**" shall be equal to 1.5.

(qqq) "**Norfolk Corporations**" means the Corporation and Norfolk Subsidiaries.

(rrr) "**Norfolk Subsidiaries**" means NPDI and NEI.

(sss) "**NPDI**" means Norfolk Power Distribution Inc., a corporation incorporated under the OBCA, licensed by the OEB to distribute electricity in Ontario, and a wholly-owned subsidiary of the Corporation.

(ttt) "**OBCA**" means the *Business Corporations Act* (Ontario), as in effect on the date hereof.

(uuu) "**OEB**" means the Ontario Energy Board and its successors.

(vvv) "**OEB Act**" means the *Ontario Energy Board Act, 1998*, as in effect on the date hereof.

(www) "**OEB Approval**" means the approval of the OEB to the Transactions contemplated herein pursuant to the OEB Act.

(xxx) "**OEB Percent Rate Reduction**" means the percentage by which the arithmetic average of Reduced Rates is lower than the arithmetic average of Current Rates.

(yyy) "**OMERS Plan**" means the Ontario Municipal Employees Retirement System Primary Pension Plan.

(zzz) "**Party**" means a party to this Agreement, and "**Parties**" means both of them.

(aaaa) "**Person**" means any individual, partnership, limited partnership, joint venture, syndicate, sole proprietorship, company or corporation with or without share capital, unincorporated association, trust, trustee, executor, administrator or other legal personal Representative, regulatory body or agency, government or governmental agency, authority or entity however designated or constituted.

(bbbb) "**PILs**" means payment in lieu of corporate taxes required to be made under Section 93 of the EA.

(cccc) "**Pole Purchase and Sale Agreement**" has the meaning set forth in Section 6.9.

(dddd) "**Proposal Date**" means February 1, 2013.

(eeee) "**Property**" means the property and assets used by the Norfolk Corporations to conduct its respective Business, including without limitation, the Real Property, the Leased Property, the Easements, the Intellectual Property and Fixed Assets.

(ffff) "**Purchaser**" means Hydro One Inc. a corporation incorporated under the laws of Ontario.

(gggg) "**Purchase Price**" has the meaning ascribed thereto in Section 2.2.

(hhhh) "**Purchased Shares**" has the meaning ascribed thereto in Section 2.1.

(iiii) "**Purchaser's Objection**" has the meaning ascribed thereto in Section 2.4(b).

(jjjj) "**Rate**" or "**Rates**" means the rate or rates for the distribution of electricity.

(kkkk) "**Rate Adjustment Difference**" means a difference equal to one percent (1%) minus the OEB Percent Rate Reduction.

(llll) "**Rate Adjustment Factor**" means a factor equal to the Rate Adjustment Difference divided by one percent (1%).

(mmmm) "**Rate Application**" means an application to the OEB for an order approving or fixing Rates.

(nnnn) "**Rate Class**" means those classes of Rates specified in Schedule 6.7 of this Agreement.

(oooo) "**Rate Freeze Period**" means the period commencing on the Closing Date and ending on the date which is five (5) years after the Closing Date.

(pppp) "**Rate Order**" means the order issued by the OEB approving the NPDI Rates, as of the Effective Date, and as set out in matter is EB-2011-0272.

(qqqq) "**Real Property**" has the meaning ascribed thereto in Subsection 3.1(l).

(rrrr) "**Reduced Rates**" has the meaning ascribed thereto in Section 6.7.

(ssss) "**Reduced Rate Effective Date**" has the meaning ascribed thereto in Section 2.6(b) of this Agreement.

(tttt) "**Release**" has the meaning ascribed thereto in any Environmental Law and includes, without limitation, any presence, release, spill, leak, pumping, pouring, addition, emission, emptying, discharge, injection, escape, leaching, disposal, dispersal, migration, dumping, deposit, spraying, burial, abandonment, incineration, seepage or placement.

(uuuu) "**Remedial Order**" means any complaint, direction, order or sanction issued, filed or imposed by any governmental authority pursuant to any Environmental Law and includes any order requiring any remediation or clean-up of any Hazardous Substance or requiring that any Release or any other activity be reduced, modified or eliminated.

(vvvv) "**Representative**" means, with respect to any Party, its Affiliates and, if applicable, its and their respective directors, officers, employees, agents and other representatives and advisors.

(wwww) "**Required Approval**" has the meaning ascribed thereto in Section 7.1.

(xxxx) "**RFP Offers**" means offers and related documents and information received from third parties, excluding the Purchaser, in response to the Corporation's Requests for Proposals and Confidential Information Memorandum for transactions involving the Norfolk Subsidiaries, dated December 7, 2012.

(yyyy) "**Statutory Plans**" means benefit plans that the Norfolk Corporations are required by domestic or foreign statutes to participate in or contribute to in respect of an employee, director or officer of the Norfolk Corporations or any beneficiary or dependent thereof, including the Canada Pension Plan, and plans administered pursuant to applicable health, Tax, workplace safety insurance, workers' compensation and employment insurance legislation.

(zzzz) "**Shareholder Declaration**" means the shareholder direction and unanimous shareholder declaration of the Vendor establishing certain principles of governance relating to the Corporation and Norfolk Subsidiaries, dated January 10, 2012.

(aaaaa) "**Subsidiary**" has the meaning ascribed thereto in the OBCA.

(bbbbb) "**Tax**" or "**Taxes**" means the PILs payable pursuant to Section 93 of the EA and all domestic and foreign federal, provincial, state, municipal, territorial or other taxes, imposts, rates, levies, assessments and government fees, charges or dues lawfully levied, assessed or imposed against the Norfolk Corporations including, without limitation, all income, capital gains, sales, excise, use, property, capital, goods and services, business transfer and value added taxes, all customs and import duties, workers' compensation premiums, Canada Pension Plan premiums, Employment Insurance premiums, and special payments pursuant to Part VI of the EA together with all interest, fines and penalties with respect thereto.

(ccccc) "**Tax Return**" means all returns, declarations, designations, forms, schedules, reports and other documents of every nature whatsoever required to be filed with any Governmental

Authority with respect to any Taxes, including those required pursuant to Part VI of the EA.

(ddddd) **"Tax Act"** means the *Income Tax Act* (Canada) and any regulations thereunder.

(eeeee) **"Third Party Claim"** has the meaning ascribed thereto in Section 12.3.

(fffff) **"Time of Closing"** means 10:00 am (Toronto time) on the Closing Date.

(ggggg) **"Total Rate Reduction Payment Amount"** means the Five-Year Fixed Payment Amount plus the Decision Period Payment Amount.

(hhhhh) **"Transactions"** means the purchase and sale of the Purchased Shares and all other transactions contemplated by this Agreement.

(iiiii) **"Vendor"** means the Corporation of Norfolk County.

(jjjjj) **"Vendor's Counsel"** means Borden Ladner Gervais LLP.

(kkkkk) **"Working Capital"** means the working capital of the Corporation, which is the amount by which the net book value of the current assets, excluding cash, of the Corporation exceeds the net book value of the current liabilities. The current assets of the Corporation are the sum of accounts receivable, unbilled revenue, income taxes recoverable, prepaid expenses and inventory. The current liabilities of the Corporation are the sum of the accounts payable, income taxes payable, deferred income, current portion of customer deposits, demand loan and current portion of long term debt. The calculation of the net book value of assets and liabilities will be based upon GAAP.

(lllll) **"Working Capital Calculation"** has the meaning ascribed thereto in Section 2.4(a)(i).

(mmmmm) **"Year End Working Capital"** has the meaning ascribed thereto in Section 2.4(a)(i).

1.2 **Construction.** This Agreement has been negotiated by each Party with the benefit of legal representation, and any rule of construction to the effect that any ambiguities are to be resolved against the drafting party does not apply to the construction or interpretation of this Agreement.

1.3 **Certain Rules of Interpretation.** In this Agreement:

(a) the division into Articles and Sections and the insertion of headings and the Table of Contents are for convenience of reference only and do not affect the construction or interpretation of this Agreement;

(b) the expressions "hereof", "herein", "hereto", "hereunder", "hereby" and similar expressions refer to this Agreement and not to any particular portion of this Agreement; and

(c) unless specified otherwise or the context otherwise requires:

(i) references to any Article, Section or Schedule are references to the Article or Section of, or Schedule to, this Agreement;

(ii) "including" or "includes" means "including (or includes) but is not limited to" and is not to be construed to limit any general statement preceding it to the specific or similar items or matters immediately following it;

(iii) "the aggregate of", "the total of", "the sum of", or a phrase of similar meaning means "the aggregate (or total or sum), without duplication, of";

(iv) references to Contracts are deemed to include all present amendments, supplements, restatements and replacements to those Contracts as of the date of this Agreement;

(v) references to any legislation, statutory instrument or regulation or a section thereof are references to the legislation, statutory instrument, regulation or section as of the date of this Agreement;

(vi) words in the singular include the plural and vice-versa and words in one gender include all genders.

1.4 **Knowledge**. In this Agreement, any reference to the knowledge of the Vendor means to the best of the knowledge, information and belief of the Vendor after reviewing all relevant records and making due inquiries regarding the relevant matter of all relevant Representatives and Affiliate Representatives of the Vendor.

1.5 **Computation of Time.** In this Agreement, unless specified otherwise or the context otherwise requires:

(a) a reference to a period of days is deemed to begin on the first day after the event that started the period and to end at 5:00 p.m. on the last day of the period, but if the last day of the period does not fall on a Business Day, the period ends at 5:00 p.m. on the next succeeding Business Day;

(b) all references to specific dates mean 11:59 p.m. on the dates;

(c) all references to specific times are references to Toronto time; and

(d) with respect to the calculation of any period of time, references to "from" mean "from and excluding" and references to "to" or "until" mean "to and including".

1.6 **Performance on Business Days.** If any action is required to be taken pursuant to this Agreement on or by a specified date that is not a Business Day, the action is valid if taken on or by the next succeeding Business Day.

1.7 **Calculation of Interest.** In calculating interest payable under this Agreement for any period of time, the first day of the period is included and the last day is excluded.

1.8 **Currency and Payment.** In this Agreement, unless specified otherwise:

(a) references to dollar amounts or "$" are to Canadian dollars;

(b) any payment is to be made by an official bank draft drawn on a Canadian chartered bank, wire transfer or any other method (other than cash payment) that provides immediately available funds; and

(c) except in the case of any payment due on the Closing Date, any payment due on a particular day must be received and available by 2:00 p.m. on the due date and any payment received and available after that time is deemed to have been made and received on the next succeeding Business Day.

1.9 **Schedules and Exhibits.** The following schedules are attached to and form part of this Agreement:

Schedule 1.1(gg)	-	Draft Financial Statements
Schedule 2.3	-	Form of Escrow Agreement
Schedule 3.1(l)	-	Real Property, Leased Property and Easements
Schedule 3.1(m)	-	Intellectual Property
Schedule 3.1(n)	-	Contracts and Commitments
Schedule 3.1(o)	-	Material Contracts
Schedule 3.1(p)	-	Employee Plans
Schedule 3.1(q)	-	Collective Agreement
Schedule 3.1(r)	-	Employees
Schedule 3.1(s)	-	Insurance Policies
Schedule 3.1(t)	-	Environmental Disclosure
Schedule 3.1(u)	-	Vendor Litigation
Schedule 3.1(v)	-	Taxes
Schedule 3.1(x)	-	Permitted Encumbrances
Schedule 3.1(z)	-	Licences
Schedule 3.1(aa)	-	Bank Accounts
Schedule 5.2		Permitted Dispositions
Schedule 6.1	-	Community Involvement
Schedule 6.6	-	CapEx
Schedule 6.7	-	Rate Harmonization for NPDI
Schedule 6.9	-	Form of Pole Purchase Agreement

ARTICLE II
PURCHASE AND SALE OF PURCHASED SHARES

2.1 **Purchase and Sale of Purchased Shares.** Subject to the terms and conditions hereof, the Vendor agrees to sell, assign and transfer to the Purchaser and the Purchaser agrees to purchase from the Vendor all of the issued and outstanding shares of the Corporation, as described in the table below (the "Purchased Shares"):

Class of Shares	Issued	Shareholder
Common Shares	2,000	Vendor

2.2 **Purchase Price.** The purchase price payable by the Purchaser to the Vendor for the Purchased Shares (the "Purchase Price") shall, subject to any adjustment in accordance with Section 2.4, be equal to the difference between Ninety Three Million dollars ($93,000,000) and the amount of Long Term Debt, which shall remain the indebtedness of the Norfolk Corporations after Closing.

2.3 **Payment of Purchase Price**

The Purchase Price shall be payable as follows:

(a) concurrently with the execution and delivery of this Agreement, the sum of four million nine hundred and ninety thousand dollars ($4,990,000) delivered to the Vendor's Counsel, which together with the sum of ten thousand dollars ($10,000) delivered by the Purchaser to the Vendor's Counsel upon signing the Confidentiality Agreement shall hereinafter be referred to as the "Deposit", and such Deposit to be held by Vendor's Counsel in trust and released in accordance with the terms and conditions of the Escrow Agreement; and

(b) at the Time of Closing, an amount equal to Ninety Three Million dollars ($93,000,000), less the Deposit and the amount of Initial Long Term Debt, being Sixty One Million Two Thousand Five Hundred and Forty-Three dollars ($61,002,543) by wire transfer of immediately available funds to the Vendor; and

(c) if applicable, the amounts payable pursuant to Section 2.4(c) below.

2.4 **Adjustment to Purchase Price.**

(a) Subject to Section 2.5, within ninety (90) days following the Closing Date, the Vendor shall cause the preparation and delivery of the Closing Date Financial Statements together with the Working Capital Calculation, the NFA Calculation, and the Long Term Debt Calculation, to the Parties, all of which shall be audited by the Auditors. The Purchase Price contemplated in Section 2.2 shall be adjusted as follows:

    (i) the Working Capital calculated based on the Financial Statements (the "Year End Working Capital"), as compared to the Working Capital calculated based on the Closing Financial Statements (the "Closing Date Working Capital") (such calculation to be referred to herein as the "Working Capital Calculation");

    (ii) the Closing Date NFA as compared to an amount equal to fifty five million eighty-five thousand and one hundred and twenty dollars ($55,085,120) (such calculation to be referred to herein as the "NFA Calculation"); and

    (iii) the Long Term Debt as compared to the Initial Long Term Debt (such calculation to be referred to herein as the "Long Term Debt Calculation").

The Purchaser shall pay the Vendor, as applicable, on a dollar for dollar basis: (A) the amount by which the Closing Date Working Capital exceeds the Year End Working Capital; (B) an amount equal to the amount obtained when the NFA Index is multiplied by the amount by which the Closing Date NFA exceeds $55,085,120; and (C) the Initial Long Term Debt exceeds the Long Term Debt. The Vendor shall pay the Purchaser, as applicable, on a dollar for dollar basis, (A) the amount by which the Year End Working Capital exceeds the Closing Date Working Capital; (B) an amount equal to the amount obtained when the NFA Index is multiplied by the amount by which the Closing Date NFA is less than $55,085,120; and (C) the amount by which the Long Term Debt exceeds the Initial Long Term Debt.

(b) The Purchaser shall have a period of thirty (30) Business Days from the later of (i) the receipt of the Closing Date Financial Statements, the Working Capital Calculation, the NFA Calculation, and the Long Term Debt Calculation; and (ii) the date on which the Purchaser is provided with access to the Auditor's working papers relating to the Closing Date Financial Statements, the Working Capital Calculation, the NFA Calculation, and the Long Term Debt Calculation within which to notify the Vendor in writing that it disputes any amounts contained in the Closing Date Financial Statements, the Working Capital Calculation, the NFA Calculation, and/or the Long Term Debt Calculation (the "Purchaser's Objection"), failing which the Purchaser shall be deemed to have accepted such amounts. The Purchaser's Objection shall set forth a specific description of the basis of the Purchaser's Objection and the adjustments to the Closing Date Financial Statements, the Working Capital Calculation, the NFA Calculation, and/or the Long Term Debt Calculation which the Purchaser believes should be made. Any items not specifically disputed during such thirty (30) Business Day period shall be deemed to have been accepted by the Purchaser.

(c) Payment of the adjustment to the Purchase Price pursuant to Section 2.4(a) shall be made by the applicable Party within thirty (30) Business Days following the later of (i) the date that the Closing Date Financial Statements , the Working Capital Calculation, the NFA Calculation, and the Long Term Debt Calculation are received by the Purchaser; and (ii) the date on which the Purchaser is provided with access to the Auditor's working papers relating to the Closing Date Financial Statements, the Working Capital Calculation, the NFA Calculation, and the Long Term Debt Calculation.

(d) If the Vendor and the Purchaser cannot agree on the adjustment of the Purchase Price pursuant to Section 2.4(a) within the time limit for payment of the adjustment to the Purchase Price pursuant to Section 2.4(b), the Vendor and the Purchaser will submit any unresolved matter within a further five (5) day period, to an independent, nationally recognized accounting firm selected by the Vendor and the Purchaser (the "Independent Auditor") for resolution or, failing agreement, as appointed by the Ontario Superior Court of Justice. The Independent Auditor will be given access to all materials and information reasonably requested by it for such purpose. The rules and procedures to be followed in the arbitration proceedings will be determined by the Independent Auditor in its discretion. The Independent Auditor will make its determination as soon as practicable and, in any case, within thirty (30) days of the matter being submitted to it. The Independent Auditor determination of all such matters will be final and binding on all Parties and will not be subject to appeal by any party. The fees and expenses of the Independent Auditor will be borne equally between the Vendor and the Purchaser. The Closing Date Financial Statements and amounts specified in Section 2.4(a) will be modified to the extent required to give effect to the Independent Auditor's determination and will be deemed to have been approved as of the date of such determination.

2.5 **Access.** The Purchaser shall provide the Vendor and the Auditors with timely access to all books, records, documents, materials, and other information and Representatives of any of the Norfolk Corporations reasonably requested by the Vendor for purposes of preparation and delivery of the Closing Date Financial Statements together with the Working Capital Calculation, the NFA Calculation, and the Long Term Debt Calculation.

2.6 **Rate Reduction Adjustment.**

(a) In the event the OEB does not approve the Negative Rate Rider, the Purchaser shall pay the Vendor, within five (5) Business Days from the Closing Date, a lump sum amount equal to $490,000.00 in immediately available funds.

(b) In the event that the OEB approves the Negative Rate Rider with an effective date occurring after the Closing Date (the "Reduced Rate Effective Date"), the Purchaser shall pay the Vendor, within five (5) Business Days from the Closing Date, an amount equal to one percent (1%) of the total Distribution Services Revenues received during the period between the Closing Date and the Reduced Rate Effective Date.

(c) In the event that the OEB approves a Negative Rate Rider but such Negative Rate Rider results in an average reduction in Rates of less than one percent (1%), the Purchaser shall pay the Vendor the Total Rate Reduction Payment Amount within five (5) Business Days from the Closing Date.

ARTICLE III
REPRESENTATIONS AND WARRANTIES

3.1 **Representations and Warranties of the Vendor.** The Vendor represents and warrants to the Purchaser as follows and acknowledges that, except as otherwise expressly provided herein, the Purchaser is relying on such representations and warranties in connection with the transactions contemplated herein. The Vendor further represents and warrants that the existence of matters in this section 3.1 qualified as to the absence of a "Material Adverse Effect", when taken together, will not have a Material Adverse Effect:

(a) **Organization.** Each of the Norfolk Corporations is a corporation duly incorporated and validly subsisting under the Laws of the Province of Ontario and has the corporate power, capacity and authority to own or lease or dispose of its property and assets and to carry on its business under the Laws of the Province of Ontario. No proceedings have been instituted or are pending for the dissolution, winding up or liquidation of any of the Norfolk Corporations.

(b) **Corporate Power of the Vendor and Due Authorization.** The Vendor has all requisite and statutory power, authority and capacity to enter into, and to perform its obligations under this Agreement and to transfer the legal and beneficial title and ownership of the Purchased Shares to the Purchaser free and clear of all Encumbrances. The Vendor has duly taken, or has caused to be taken, all action required to be taken by the Vendor to authorize the execution and delivery of this Agreement by the Vendor in the performance of its obligations hereunder.

(c) **Binding Agreement.** This Agreement has been duly executed by the Vendor and will, upon delivery, constitute a valid and binding obligation of the Vendor, enforceable against it in accordance with its terms, except as enforcement may be limited by bankruptcy, insolvency and other Applicable Laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction.

(d) **Authorized and Issued Capital of the Corporation.** The authorized share capital of the Corporation consists of an unlimited number of Common Shares, of which only the Purchased Shares have been validly allotted and issued and are outstanding as fully paid and non-assessable shares, and will be the only outstanding shares of the Corporation at the Time of Closing.

(e) **Ownership of Shares.**

(i) The Vendor is the sole beneficial and registered owner of the Purchased Shares, with good and marketable title thereto, free and clear of all Encumbrances (other than the rights of the Purchaser hereunder) and has the exclusive right to dispose of the Purchased Shares as herein provided. Without limiting the generality of the foregoing, except for the Shareholder Declaration, none of the Purchased Shares is subject to any voting trust, shareholder agreement or voting agreement.

(ii) The Corporation is the sole beneficial and registered owner of all of the shares of each of the Norfolk Corporations, with good and marketable title thereto, free and clear of all Encumbrances.

(f) **Options.** No Person (other than the Purchaser under this Agreement) has the benefit of any Contract or any right or privilege (whether by Applicable Law, pre-emptive or contractual) binding upon or which may at any time in the future become binding upon the Vendor to acquire or obtain in any other way an interest in any of the Purchased Shares or the shares of any of the Norfolk Corporations.

(g) **Subsidiaries.** The Norfolk Subsidiaries are the only Subsidiaries of the Corporation and none of the Norfolk Corporations owns or has any interest in any shares of any other corporation.

(h) **No Violations.** Neither the execution nor delivery of this Agreement nor the completion of the transactions herein contemplated will result in the violation of:

(i) any provision of the by-laws of the Vendor;

(ii) any Contract to which the Vendor or any of the Norfolk Corporations is a party or by which the Vendor, the Norfolk Corporations or any of their respective

Properties is bound, which would have a material adverse effect on the Vendor's ability to perform its obligations under this Agreement; or

(iii) subject to the Required Approval, to the Vendor's knowledge, any Applicable Law or requirement of a Government Authority having jurisdiction over each of the Vendor and Norfolk Corporations, which would have a material adverse effect on the Vendor's ability to perform its obligations under this Agreement.

(i) **Consents and Approvals.** Other than the Required Approval, there is no requirement for the Vendor or any of the Norfolk Corporations to make any filing with, give any notice to or obtain any licence, permit, certificate, registration, authorization, consent or approval of, any Government Authority as a condition to the lawful consummation of the Transaction.

(j) **Compliance with Applicable Law.** Each of the Norfolk Corporations has complied in all material respects with all Applicable Laws relating to its respective Business, the failure to comply with which would have a Material Adverse Effect. None of the Norfolk Corporations is in violation or default under, and to the best of the Vendor's knowledge, no event has occurred which, with the lapse of time or the giving of notice or both, would result in the violation of or default under, the terms of any judgment, decree, order injunction or writ of any court or other Government Authority with respect to the Business of any of the Norfolk Corporations, which would have a Material Adverse Effect.

(k) **Corporate Records.** The corporate records and minute books of the Norfolk Corporations produced by the Vendor are in all material respects a complete and accurate record of the material business transacted at meetings of, and contain all resolutions passed by, the directors and the sole shareholder of the Norfolk Corporations held since the respective incorporation of each of the Norfolk Corporations. To the Vendor's knowledge, each and all such meetings were duly called and held and all such resolutions and by-laws were duly passed. The share certificate books, registers of shareholders, registers of transfers, registers of directors and other corporate registers of each are complete and accurate.

(l) **Real Property.**

(i) To the Vendor's knowledge, Schedule 3.1(l) sets forth a list of lands owned in fee simple (the "Real Property") and leased property (the "Leased Property") by each of the Norfolk Corporations.

(ii) To the Vendor's knowledge, none of the Norfolk Corporations owns any real property or has rights under any leases, or has agreed to acquire or lease, any real property other than that listed in Part I of Schedule 3.1(l).

(iii) Neither the Vendor, nor any of the Norfolk Corporations, has received any, nor to the Vendor's knowledge are there any pending or threatened, notices of violation or alleged violation of any Applicable Laws against or affecting any Real Property or Leased Property.

(iv) The Norfolk Corporations have such rights of occupancy, possession, use, entry and exit, as applicable, to and from Real Property, Leased Property and Easements as are reasonably necessary to carry on their respective Business.

(v) Other than listed in Part II of Schedule 3.1(l), which encumbrances Vendor covenants to remove prior to Closing subject to those conditions in Section 5.10, no Person has any right to purchase any of the Real Property and no Person other than the Norfolk Corporations is using or has any right to use, is in possession or occupancy, of any part of the Real Property.

(vi) There exists no option, right of first refusal or other contractual rights with respect to any of the Real Property.

(vii) Other than listed in Part II of Schedule 3.1(l), which encumbrances Vendor covenants to remove prior to Closing subject to those conditions in Section 5.10, neither the Vendor, nor any of the Norfolk Corporations, has entered into any contract to sell, transfer, encumber, or otherwise dispose of or impair the right, title and interest of the Norfolk Corporation in and to Real Property, Leased Property, or the air, density and easement rights relating to such Real Property or Leased Property, as may be applicable.

(viii) Neither the Vendor, nor any of the Norfolk Corporations, has received any notification of, nor are there any outstanding or incomplete work orders in respect of any Fixed Assets on such Real Property, Leased Property, Easements or of any current non-compliance (other than non-compliances which are legal non-conforming under relevant zoning by-laws) with Applicable Law, including without limitation, building and zoning by-laws and regulations, and to the Vendor's knowledge, no by-law which would adversely affect the Business of any of the Norfolk Corporations is currently being contemplated by the Vendor.

(ix) All accounts for work and services performed or materials placed or furnished upon or in respect of the construction and completion of any Fixed Assets constructed on Real Property, Leased Property or Easements have been fully paid and, to the Vendor's knowledge, no Person is entitled to claim a lien under the *Construction Lien Act* (Ontario) or other similar legislation for such work.

(x) To the Vendor's knowledge, there are no matters affecting the right, title and interest of the Norfolk Corporations, as applicable, in and to the Real Property, Leased Property or Easements which would materially and adversely affect the ability of any of the Norfolk Corporations to carry on its respective Business thereon.

(m) **Intellectual Property.** Schedule 3.1(m) sets forth and describes all trade secrets and any licensed property or technology used in whole or in part by each of the Norfolk Corporation's respective Business, and all material trademarks, tradenames, service marks, brand names, patents, copyrights, industrial designs and other industrial property rights, and all applications therefor, in each case specifying whether the item is owned by each of the Norfolk Corporations or is used by each of the Norfolk Corporations under a licence agreement or arrangement from another Person.

(n) **Contracts and Commitments.** Except as set forth in Schedule 3.1(n), none of the Norfolk Corporations is a party to or bound by any of the following:

(i) any offer letter, employment or consulting Contract or any other written Contract with any officer, employee or consultant, including any agreements or arrangements relating to compensation, other than oral Contracts of indefinite hire terminable by the employer without cause on reasonable notice;

(ii) any agreement, contract or commitment limiting the freedom of the Corporation to engage in any line of business or to compete with another Person; or

(iii) any Material Contract.

(o) **Material Contracts.** The Vendor has previously delivered or will make available to the Purchaser at Closing, true and complete copies of all Material Contracts, all of which are in full force and effect and unamended and no material default exists under such Material Contracts on the part of the respective Norfolk Corporation or, on the part of any other party to such Contracts, and there are no current or pending negotiations with respect to the renewal, repudiation or amendment of any such Material Contract. The Material Contracts comply with the terms of the Collective Agreement. Except as set forth in Schedule 3.1(o), to the Vendor's knowledge, the materials provided in the Data Room folder entitled "Material Contracts", and those Contracts listed in Schedule 3.1(n) are true and complete copies of all Contracts of the Norfolk Corporations as of the Proposal Date.

(p) **Employee Plans.**

(i) Except as set forth and described in Schedule 3.1(n) and Schedule 3.1(p), none of the Norfolk Corporations are party to, bound by, subject to or have any liability relating to any employment agreement or any agreement or arrangement relating to information provided under Section 3.1(n), deferred compensation, bonus, incentive or other compensation, commission, fee, profit-sharing, severance, termination pay, supplementary employment insurance, vacation entitlements, insurance, health, welfare, disability, pension, retirement, hospitalization, medical, prescription drug, dental, eye care, arrangements for personal use of any corporate assets based on past practice and other similar benefits, plans or arrangements, (the "Employee Plans"), whether funded or unfunded, formal or informal, written or unwritten, that is maintained, contributed to, or required to be maintained or contributed to, by the Norfolk Corporations, or to which the Norfolk Corporations is a party, for the benefit of the Employees and their respective beneficiaries and dependents, other than Statutory Plans, nor are any of the Norfolk Corporations in arrears in the payment of any contribution or assessment required to be made by them pursuant to any agreements or arrangements relating to Employee Plans.

(ii) Other than the OMERS Plan and MEARIE Policy 331268, a true and complete copy of each Employee Plan (as amended to date) has been provided to the Purchaser together with true and complete copies of all documents relating to each such Employee Plan, including, as applicable, all booklets, summaries, notices or manuals prepared for or circulated to Employees generally concerning each such Employee Plan.

(iii) All obligations of the Norfolk Corporations due prior to Closing under the Employee Plans and the Statutory Plans (whether pursuant to the terms thereof or any Applicable Law) have been satisfied in all material respects.

(iv) Other than the OMERS Plan, with respect to which the Vendor makes no representation, and other than any material grievance that has been resolved or settled, as applicable, all Employee Plans are, and have been, established, registered (where required), and administered without default, in material compliance with (i) the terms thereof; and (ii) all Applicable Law; and neither the Vendor, nor any Norfolk Corporation has received, in the last four (4) years, any notice from any Person questioning or challenging such compliance (other than in respect of any claim related solely to that Person), nor does the Vendor have any knowledge of any such notice from any Person questioning or challenging such compliance beyond the last four (4) years. Except as disclosed in Schedule 3.1(p), and other than the OMERS Plan, and as set out in the Collective Agreement, there are no promised improvements, increases or changes to, the benefits provided under any Employee Plan, nor does any Employee Plan provide for benefit increases or the acceleration of funding obligations that are contingent upon or will be triggered by the execution of this Agreement or the Closing.

(v) Except as disclosed in Schedule 3.1(p), no Employee Plan, other than the OMERS Plan, provides benefits beyond retirement or other termination of service to employees or former employees of the Norfolk Corporations or to the beneficiaries or dependants of such employees or former employees. Other than the OMERS Plan, no Employee Plan requires or permits a retroactive increase in premiums or payments.

(vi) All employee data necessary to administer the Norfolk Corporations' participation in the OMERS Plan and the other Employee Plans is in the possession of the relevant Norfolk Corporation and is complete, correct and in a form which is sufficient for the proper administration of the Norfolk Corporations' participation in the OMERS Plan and the other Employee Plans in accordance with the terms thereof and all Applicable Law.

(q) **Labour Matters**

(i) Except as set forth in Schedule 3.1(q) (the "**Collective Agreement**") the Norfolk Corporations are not a party to or bound by or subject to any agreement or arrangement with any labour union or employee association and has not made any commitment to or conducted any negotiation or discussion with any labour union or employee association with respect to any future agreement or arrangement.

(ii) There is no strike or lockout occurring or affecting, or to the Vendor's knowledge threatened against, any of the Norfolk Corporations.

(r) **Employees.**

(i) The Purchaser has been provided with a complete and accurate list of the names of all individuals who are employees (the "Employees") of each of the Norfolk Corporations specifying title, compensation, years of service, whether they are union or non-union, and the benefits under the Employee Plans to which they are entitled (the "Employee Fact Sheet").

(ii) Except as disclosed in Schedule 3.1(r), no Employee is on long-term disability leave, extended absence or receiving benefits pursuant to the *Workplace Safety and Insurance Act* (Ontario).

(iii) Each of the Norfolk Corporations has been operated in material compliance with all laws relating to employees, including employment standards and all laws relating to full or in part to the protection of employee health and safety, human rights, labour relations and pay equity. Except as disclosed in Schedule 3.1(r):

(A) there have been no Claims nor, to the best of the Vendor's knowledge, are there any threatened complaints, under such laws against any of the Norfolk Corporations;

(B) to the Vendor's knowledge, nothing has occurred which might lead to a Claim or complaint against any of the Norfolk Corporations, under any such laws; and

(C) there are no outstanding decisions or settlements or pending settlements which place any obligation upon any of the Norfolk Corporations to do or refrain from doing any act.

(iv) All assessments under the *Workplace Safety and Insurance Act* (Ontario) in relation to the Business of each of the Norfolk Corporations have been paid or accrued and none of the Norfolk Corporations is subject to any special or penalty assessment under such legislation which has not been paid.

(s) **Insurance.** Schedule 3.1(s) sets forth all insurance policies, other than those already disclosed in the Schedule 3.1(p), specifying: (i) any pending claims thereunder, maintained by each of the Norfolk Corporations on its Property; or (ii) any material pending claims under polices maintained by each of the Norfolk Corporations in respect of its Employees, excluding pending claims made in the ordinary course of Business.

(t) **Environmental.**

To the knowledge of the Vendor:

(i) other than as specified in Schedule 3.1(t), all operations of the Norfolk Corporations conducted on or at the Real Property and Leased Property while occupied or used by the Norfolk Corporations, have been and are now in compliance in all material respects with all applicable Environmental Laws. Any Release by the Norfolk Corporations, of any Hazardous Substance into the Environment complied and complies in all material respects with all applicable Environmental Laws, and not in a manner that could reasonably be expected to have a Material Adverse Effect;

(ii) the Norfolk Corporations have obtained all requisite Environmental Approvals, which Environmental Approvals are valid and in full force and effect, have been and are being complied with in all material respects and there have been and are no proceedings commenced or threatened to revoke or amend any Environmental Approvals in a manner that could reasonably be expected to have a Material Adverse Effect. Schedule 3.1(t) lists all of the Environmental Approvals in the possession of the Norfolk Corporations;

(iii) the Norfolk Corporations have not been and are not now the subject of any Remedial Order nor, is any investigation or evaluation threatened or commenced as to whether any such Remedial Order is necessary;

(iv) the Norfolk Corporations have never been prosecuted for or convicted of any offence under Environmental Laws, nor has any of them been found liable in any proceeding to pay any damages, fine or judgment to any Person as a result of any Release or threatened Release of any Hazardous Substance into the Environment or as the result of any breach of any Environmental Laws. No notice has been received by the Vendor or by the Norfolk Corporations of any investigation or evaluation by any Governmental Authority or of any claims, pending or threatened, and there are no investigations or evaluations threatened or commenced as to whether any offence by any of the foregoing has occurred. There are no Claims that have been threatened or commenced against any of the Norfolk Corporations as a result of any Release or threatened Release of any Hazardous Substance into the Environment or as the result of the breach of any Environmental Laws;

(v) no part of the Real Property or Leased Property has ever been used by the Norfolk Corporations as a landfill or for the disposal of waste;

(vi) except as disclosed in Schedule 3.1(t), no asbestos, asbestos containing materials, polychlorinated biphenyls ("PCBs") and PCB wastes are used or stored by the Norfolk Corporations or otherwise present in or on the Real Property, or used or stored by the Norfolk Corporations on the Leased Property except for PCBs contained in the electrical transformers which are in service and which form an integral part of, and are necessary for the operation of their respective Business. The Vendor has disclosed to the Purchaser all inspection reports received from the Ministry of the Environment in connection with the Commission's handling, transportation and storage of PCBs;

(vii) except as disclosed in Schedule 3.1(t), there has been no Release by any of the Norfolk Corporations which is now present in, on or under any of the Real Property, Leased Property or any neighbouring or adjoining property (including, without limitation, underlying soils and substrata, surface water, ground water and vegetation) at levels which exceed decommissioning or remediation standards under any applicable Environmental Laws or standards published or administered by those governmental authorities responsible for establishing or applying such standard or in a manner that could reasonably be expected to have a Material Adverse Effect;

(viii) there are no Hazardous Substances in, on or under the Real Property and there are no underground storage tanks on the Real Property and any underground storage tanks formerly on the Real Property have been removed and any affected soil, surface water or ground water has been remediated in compliance with all Applicable Law including, without limitation, Environmental Law.

(u) **Litigation.** Except as set out in Schedule 3.1(u), there are no actions, suits or proceedings (whether or not purportedly on behalf of a Norfolk Corporation) pending or, to the Vendor's knowledge, threatened against or affecting, a Norfolk Corporation at law or in equity, or before or by any federal, provincial, municipal or other governmental department, court, commission, board, bureau, agency or instrumentality, domestic or foreign, or by or before an arbitrator or arbitration board which, either individually or in the aggregate, would have a Material Adverse Effect.

(v) **Taxes.**

(i) Each of the Norfolk Corporations is exempt from Tax under the Tax Act and the CTA but is required to make PILS payments under the EA in an amount equal to the Tax that it would be liable to pay under the Tax Act and CTA if it were not exempt from Tax under those statutes.

(ii) Each of the Norfolk Corporations has filed in the prescribed manner and within the prescribed times all Tax Returns required to be filed by it in all applicable jurisdictions with respect to taxation periods ended on or before the Closing Date. All such Tax Returns are complete and correct and disclose all Taxes required to be paid for the periods covered thereby. None of the Norfolk Corporations have ever been required to file any Tax Returns with, and have never been liable to pay or remit Taxes to, any Governmental Authority outside Canada. Each of the Norfolk Corporations has paid all Taxes and all instalments of Taxes due on or before the Closing Date. The Vendor has furnished to the Purchaser true, complete and accurate copies of all Tax Returns and any amendments thereto filed by the Norfolk Corporations since December 31, 2008 and all notices of assessment and reassessment and all correspondence with Governmental Authorities relating thereto as well as true, complete and accurate copies of all tax returns and any amendments filed at any time with respect to a taxation year that is not statute barred, and all notices of assessment and reassessment and all correspondence with Governmental Authorities or tax advisors relating thereto.

(iii) Assessments under the EA have been issued to each of the Norfolk Corporations covering all periods up to and including its fiscal year ended December 31, 2011.

(iv) There are no audits, assessments, reassessments or other Claims in progress or, to the knowledge of the Vendor, threatened against any of the Norfolk Corporations, in respect of any Taxes and, in particular, there are no currently outstanding reassessments or written enquiries which have been issued or raised by any Governmental Authority relating to any such Taxes except for those items listed in Schedule 3.1(v). The Vendor is not aware of any contingent liability of any of the Norfolk Corporations for Taxes or any grounds that could prompt an assessment or reassessment for Taxes, and none of the Norfolk Corporations have received any indication from any Governmental Authority that any assessment or reassessment is proposed with respect to taxation periods ended on or before the Closing Date.

(v) None of the Norfolk Corporations have entered into any transactions with any non-resident of Canada (for the purposes of the Tax Act) with whom the Norfolk Corporations were not dealing with at arm's length (within the meaning of the Tax Act). None of the Norfolk Corporations have acquired property from any Person in circumstances where the Corporation did or could have become liable for any Taxes payable by that Person.

(vi) None of the Norfolk Corporations have entered into any agreements, waivers or other arrangements with any Governmental Authority providing for an extension of time with respect to the issuance of any assessment or reassessment, the filing of any Tax Return, or the payment of any Taxes by or in respect of any of the Norfolk Corporations. None of the Norfolk Corporations is a party to any agreements or undertakings with respect to Taxes.

(vii) Each of the Norfolk Corporations is a registrant for purposes of the ETA, and the HST registration numbers are as follows:

NPI	88974 1211
NPDI	86289 2593
NEI	86289 0399

All input tax credits claimed by the Norfolk Corporations pursuant to the ETA have been proper, correctly calculated and documented. The Norfolk Corporations have collected and remitted when due all Taxes, including GST/HST and RST, as required by tax legislation.

(viii) Each of the Norfolk Corporations maintains its books and records in compliance with Section 230 of the Tax Act.

(w) **Withholding.** Each of the Norfolk Corporations has withheld from each payment made to any of its past or present employees, officers or directors, and to any non-resident of Canada, the amount of all Taxes and other deductions required to be withheld therefrom, including without limitation, all employee and employer portions for Workers' Compensation, Canada Pension Plan, Employer Health Tax and Employment Insurance and has paid the same to the proper tax or other receiving officers within the time required under any applicable legislation. Each of the Norfolk Corporations has remitted to the appropriate tax authority when required by law to do so all amounts collected by it on account of sales taxes including goods and services tax and harmonized sales tax.

(x) **Ownership of Property.** The Norfolk Corporations are the sole legal and beneficial, and where its interests are registrable, the sole registered owner, of all of the Property used in connection with, directly or indirectly, ancillary to, or reasonably necessary for the operation of their respective Business with good and valid title thereto free and clear of all Encumbrances other than in respect of the Real Property, Leased Property or Easements, which may be subject to minor easements for the supply of utilities, with good and marketable title to the Real Property in fee simple, and those permitted encumbrances listed in Schedule 3.1(x). As of the Effective Date, forms of leases to the Leased Property disclosed to the Purchaser are in good standing and unamended. All of the Fixed Assets used in connection with, directly or indirectly, ancillary to, or reasonably necessary for the operation of their respective Business are in good working order, condition and repair, have been properly and regularly maintained and are free of any structural defect and free from any defect in material and workmanship, are of merchantable quality and fit for the purposes of the Purchaser and are in compliance with all Applicable Laws. There has been no assignment, subletting or granting of any licence (of occupation or otherwise) of or in respect of any such Property or any granting of any contract or right capable of becoming a contract or option for the purchase of any of such Property other than pursuant to the provisions of, or as disclosed in, this Agreement.

(y) **Financial Statements.** The Financial Statements were prepared and the Closing Date Financial Statements will be prepared in accordance with GAAP applied on a basis consistent with that of the preceding period and present, or will present (in the case of the Closing Date Financial Statements), fairly:

(i) in the case of the Financial Statements, all of the assets, liabilities and financial position of the Corporation as at December 31, 2012, and the sales, earnings, results of operation and changes in financial position of the Corporation for the 12-month period then ended; and

(ii) in the case of the Closing Date Financial Statements, the assets and liabilities of the Corporation as at the Time of Closing.

(z) **Licenses.** Schedule 3.1(z) sets out a complete list of all licenses, permits, approvals, consents, certificates, registrations and authorizations ("Licenses") held by or granted to each of the Norfolk Corporations, and there are no other licences, permits, approvals, consents, certificates, registrations or authorizations necessary to carry on their respective Business. Each Licence is valid, subsisting and in good standing and none of the Norfolk Corporations are set in default or in breach of any Licence and, to the best of the Vendor's knowledge, no proceeding is threatened or pending to revoke or limit any Licence.

(aa) **Bank Accounts.** Schedule 3.1(aa) sets forth a complete list of every financial institution in which each of the Norfolk Corporations maintains any depository account, trust account or safety deposit box and the names of all persons authorized to draw on or who have access to such accounts or safety deposit box.

(bb) **Absence of Guarantees.** None of the Norfolk Corporations has given, agreed to give or shall give, or is a party or bound by, any guarantee or indemnity in respect of indebtedness, or other obligations, of any Person, or any other commitment by which the relevant Norfolk Corporation is, or is contingently, responsible for such indebtedness or other obligations.

(cc) **Limitation.** The Vendor makes no representation or warranty to the Purchaser except as specifically set forth in this Agreement and this Agreement contains all representations and warranties of the Vendor relating to the Purchased Shares and the Transaction.

(dd) **Effect of Disclosure.** All disclosure contained in a particular representation and warranty set forth in this Agreement (or any Schedule referred to therein) shall be deemed for the purposes of this Agreement to have been made with respect to all of the representations and warranties in this Section 3.1 to which such disclosure might be applicable. Notwithstanding anything else contained herein, the Vendor shall have no liability to the Purchaser with respect to any failure by it to disclose the existence of any matter, document or thing, or to make any other disclosure in the context of a particular representation and warranty set out in this Section 3.1 where the existence of such matter, document or thing has been disclosed as part of another representation or warranty contained in this Agreement or in any Schedule annexed hereto.

3.2 **Representations and Warranties of the Purchaser.** The Purchaser represents and warrants to the Vendor as follows and acknowledges that the Vendor is relying on such representations and warranties in connection with the transactions contemplated herein:

(a) **Organization.** The Purchaser is a corporation duly incorporated and validly subsisting corporation under the laws of Ontario and has the corporate power to own or lease its property and assets and to carry on the business presently carried on by it.

(b) **Corporate Power of the Purchaser and Due Authorization.** The Purchaser has all requisite corporate power, authority and capacity to enter into, and to perform its obligations under this Agreement. The Purchaser has duly taken, or has caused to be taken, all corporate action required to be taken by the Purchaser to authorize the execution and delivery of this Agreement by the Purchaser in the performance of its obligations hereunder and has the financial ability to complete the Purchase and pay the Purchase Price.

(c) **Binding Agreement.** This Agreement has been duly executed by the Purchaser and will, upon delivery, constitute a valid and binding obligation of the Purchaser, enforceable against it in accordance with its terms, except as enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction.

(d) **No Violations.** Neither the execution nor delivery of this Agreement nor the completion of the transactions herein contemplated will result in the violation of:

(i) any provision of the constating documents, by-laws or any unanimous shareholder agreement of the Purchaser;

(ii) any Contract to which the Purchaser is a party or by which the Purchaser or any of its property or assets is bound, which would have a material adverse effect on the Purchaser's ability to perform its obligations under this Agreement; or

(iii) subject to obtaining the regulatory approvals set forth in Article VII, any terms or provisions of any Applicable Law of any authority having jurisdiction over the Purchaser which would have a materially adverse effect on the Purchaser's ability to perform its obligations under this Agreement.

(e) **Investment Canada Act.** The Purchaser is not a "non-Canadian" within the meaning of the *Investment Canada Act* (Canada). The Purchaser is not a "non-resident" for tax purposes.

(f) **Financial Capability.** The Purchaser has sufficient funds in place to pay the Purchase Price on the Closing Date on the terms and conditions contained in this Agreement.

(g) **Consents and Approvals.** Except for the Required Approval, there is no requirement for the Purchaser to make any filing with, give any notice to or obtain any licence, permit, certificate, registration, authorization, consent or approval of, any governmental or regulatory authority as a condition to the lawful consummation of the transactions contemplated by this Agreement.

(h) **Litigation.** There is no legal proceeding in progress, pending, threatened against or affecting the Purchaser and, to the best of the knowledge and belief of the Purchaser, there are no grounds on which any such legal proceeding might be commenced with any reasonable likelihood of success and no judgment, decree, injunction, ruling, order or award of any tribunal outstanding against or affecting the Purchaser which, in any such case, might adversely affect the ability of the Purchaser to enter into this Agreement or to perform its obligations hereunder.

(i) **Crown Corporation.** The Purchaser is a crown corporation as described in paragraph 149(1)(d) or (d.2) of the Tax Act.

(j) **Limitation.** The Purchaser makes no representation or warranty to the Vendor except as specifically set forth in this Section 3.2 and this Agreement contains all representations and warranties of the Purchaser relating to the transactions contemplated hereby.

(k) **Effect of Disclosure.** All disclosure contained in a particular representation and warranty set forth in this Agreement (or any Schedule referred to therein) shall be deemed for the purposes of this Agreement to have been made with respect to all of the representations and warranties in this Section 3.2 to which such disclosure might be applicable. Notwithstanding anything else contained herein, the Purchaser shall not have any liability to the Vendor with respect to any failure by it to disclose the existence of any matter, document or thing, or to make any other disclosure in the context of a particular representation and warranty set out in this Section 3.2 where the existence of such matter, document or thing has been disclosed as part of another representation or warranty contained in this Agreement or in any Schedule annexed hereto.

ARTICLE IV
SURVIVAL OF REPRESENTATIONS AND WARRANTIES

4.1 **Survival of Representation and Warranties.**

(a) The representations and warranties of the Vendor set out in Section 3.1 shall survive the Closing and, notwithstanding such Closing or any investigation made by or on behalf of the Purchaser with respect thereto, shall continue in full force and effect for the benefit of the Purchaser provided, however, that no Claim in respect thereof shall be valid unless it is made within a period of one (1) year from the Closing Date and, upon the expiry of such limitation period, the Vendor shall have no further liability to the Purchaser with respect to the representations and warranties referred to in such section, except in respect of Claims which have been made by the Purchaser to the Vendor in writing prior to the expiration of such period.

(b) The representations and warranties of the Purchaser set out in Section 3.2 shall survive the Closing and, notwithstanding such Closing or any investigation made by or on behalf of the Vendor with respect thereto, shall continue in full force and effect for the benefit of the Vendor provided, however, that no Claim in respect thereof shall be valid unless it is made within a period of one (1) year from the Closing Date and, upon the expiry of such limitation period, the Purchaser shall have no further liability to the Vendor with respect to the representations and warranties referred to in such section, except in respect of Claims which have been made by the Vendor to the Purchaser in writing prior to the expiration of such period.

ARTICLE V
COVENANTS OF THE VENDOR

5.1 **Access to the Corporation.** The Vendor shall forthwith make available to the Purchaser and its authorized Representatives and, if requested in writing by the Purchaser, provide a copy to the Purchaser of, all title documents, Contracts, financial statements, policies, plans, reports, licences, orders, permits, books of account, accounting records and all other documents, information and data, excluding the RFP Offers, relating to the Business. The Vendor shall afford the Purchaser and its authorized Representatives every reasonable opportunity to have free and unrestricted access to the Business, Property and records of the Norfolk Corporations. At the request of the Purchaser, the Vendor shall execute, or shall cause the relevant Norfolk Corporation to execute, such consents, authorizations and directions as may be necessary to permit any inspection of the Business or to enable the Purchaser or its authorized Representatives to obtain full access to all files and records relating to any of the Business maintained by Government Authorities. The Vendor and the Purchaser shall co-operate in good faith in arranging any such meetings as the Purchaser should reasonably request with:

(a) senior executives of the Norfolk Corporations employed in the Business;

(b) suppliers, distributors, service providers or others who have a business relationship with the Vendor and/or the Norfolk Corporations, in respect of the Business; and

(c) the exercise of any rights of inspection by or on behalf of the Purchaser under this Section 5.1 shall not mitigate or otherwise affect any of the representations and warranties of the Vendor hereunder, which shall continue in full force and effect as provided in Section 4.1.

5.2 **Conduct of Business Prior to Closing.** During the period from the date of the Financial Statements to the Closing Date, the Vendor has caused and shall cause the Business of the Norfolk Corporations to be conducted in the ordinary course substantially consistent with past practice (except as may be otherwise required or contemplated by the provisions of this Agreement), and has not sold or otherwise disposed of any of its Property, other than sales or dispositions of Property in the ordinary course not exceeding fifty thousand dollars ($50,000) in the aggregate. Other than those dispositions listed in Schedule 5.2, the Vendor shall obtain Purchaser's prior written approval if the amount of such disposition or sale is greater than fifty thousand dollars ($50,000) in the aggregate. During such period there has been no change in the Business, operation, affairs, personnel and/or financial condition of any of the Norfolk Corporations, except for changes occurring in the ordinary course of business which in aggregate have not had a Material Adverse Effect. The Parties further expressly acknowledge that, notwithstanding anything herein contained, during the period from execution of this Agreement to the Closing Date, the Norfolk Corporations shall be permitted to declare and pay dividends to their respective shareholders out of cash on hand.

5.3 **Delivery of Books and Records.**

(a) At the Time of Closing, the Vendor shall cause to be delivered to the Purchaser all of the books and records of and relating to the Norfolk Corporations and the Business; and

(b) Notwithstanding Section 5.3(a), the Vendor shall be entitled to retain copies of any documents or other data delivered to the Purchaser pursuant to Section (a) provided that those documents are reasonably required by the Vendor to perform its obligations hereunder or under Applicable Law.

5.4 **Resignation of Directors.** The Vendor shall cause all of the directors of the Norfolk Corporations to resign in favour of nominees of the Purchaser, such resignation to be effective at the Time of Closing and releases from such individuals of all claims they may have against any of the Norfolk Corporations (other than in respect of unpaid salaries and accrued vacation pay).

5.5 **No Material Contracts.** From and after the date hereof, the Norfolk Corporations shall not enter into any Material Contracts without the prior consent of the Purchaser, which consent may not be unreasonably withheld.

5.6 **Non Assignable Assets** . The Vendor will use its best efforts to obtain any consents required from third parties to the effective transfer of the Property to and for the enjoyment of the Corporation and in the absence of any such consent or effective transfer, Vendor shall hold such asset in trust for the benefit of the Norfolk Corporations, in connection with which trust Purchaser shall indemnify Vendor.

5.7 **Transfer of Purchased Shares.** The Vendor shall take, and shall cause the Corporation to take, all necessary steps and proceedings to permit the Purchased Shares to be duly and validly transferred to the Purchaser and to have such transfers duly and validly recorded on the books of the Corporation so that the Purchaser is entered onto the books of the Corporation as the holder of the Purchased Shares and to issue share certificates to the Purchaser representing the Purchased Shares.

5.8 **Transfer of Real Property.** The Vendor shall take, and shall cause the Corporation to take, all necessary steps and proceedings to transfer the real property located at 1120 Bay Street, Port Rowan to the Corporation, such that the Corporation shall have with good and valid title thereto, prior to the Closing Date.

5.9 **Termination of Certain Contracts.** At the Purchaser's option, and upon receipt of written notice from the Purchaser to the Vendor, the Vendor shall cause the applicable Norfolk Corporation to terminate all obligations of such Norfolk Corporation under the Contracts referred to in Schedule 3.1(n) as "FINN Projects – CDM Consulting Services/Small Business Lighting

Services" and "Springboard Management – Health and Safety Consulting Services", prior to Closing.

5.10 **Removal of Certain Encumbrances.**

(a) The Vendor shall:

(i) upon receipt of written notice from the Purchaser within fifteen (15) days from the Effective Date, use its reasonable commercial efforts to make an application to the applicable land registry office to have any or all of the encumbrances listed under Part II(A) of Schedule 3.1(l), in accordance with the said written notice, removed from title prior to Closing; and

(ii) The Vendor shall use its reasonable commercial efforts to make an application to the applicable land registry office to have any or all of the encumbrances listed under Part II(B) of Schedule 3.1(l) removed from title prior to Closing;

provided that, in the event such application is made by the Vendor and the applicable land registry office denies or rejects the said application, that the Vendor shall have no further obligation with respect to the matters set forth in this Section 5.10, the Purchaser shall complete the transactions contemplated herein subject to such encumbrances, and that the Vendor shall not be deemed to have failed to fulfill or perform its obligations for purposes of Section 9.2(b). For greater certainty, the Vendor shall only be required to make an application under this Section 5.10(a)(ii) if the Vendor is able to satisfy itself that the tenants under such lease agreements listed in in Part II(B) of Schedule 3.1(l) are not in possession of those said premises.

ARTICLE VI
COVENANTS OF THE PURCHASER

6.1 **Employment and Location Guarantees.** The Purchasers hereby covenants and agrees that for a period of one (1) year following the Closing Date, it will, subject to its rights to dismiss for just cause, guarantee the continued employment with the Purchaser or an Affiliate of a Purchaser, of each Employee who is an Employee of the Norfolk Corporations on the Closing Date at no less than the terms and conditions as outlined in the Employee Fact Sheet, including the same or not less favourable: (i) benefits in the aggregate; (ii) compensation; and, (iii) seniority; and to remain located in the Town of Simcoe. The foregoing shall not prohibit the relocation of Employees with their prior consent. From and after the Closing Date, Employees may apply for positions within the Purchaser and its Affiliates and will be considered for such positions on a fair and equal basis with other employees of the Purchaser and its Affiliates, with credit for their seniority and service with the applicable Norfolk Corporation.

6.2 **Participation in Community Events and Economic Development.** After Closing, the Purchaser or the Corporation shall provide community assistance to the Vendor and Norfolk County by doing such things as listed in Schedule 6.1.

6.3 **Advisory Committee.** The Purchaser shall establish an advisory committee (the "Advisory Committee") as soon as practicable after Closing to provide a forum for communication between the Purchaser and the Vendor. In establishing the Advisory Committee, the Purchaser shall select Representatives, including a local superintendent from Hydro One's Zone 2 or equivalent, in consultation with officials of the Vendor. The Vendor may appoint at least three (3) Representatives to the Advisory Committee.

6.4 **Employee Related Matters.** The Purchaser acknowledges that from and after Closing, it and the Norfolk Corporations shall be responsible for all obligations owing to present and former employees and beneficiaries of the Business relating to such employment, including all obligations and liabilities relating to wages, severance pay, notice of termination of employment or pay in lieu of such notice, damages for wrongful dismissal or other employee benefits or claims, including vacation pay, and pension plans regardless of whether these arose before or after Closing. The Purchaser shall indemnify and save harmless the Vendor from and against any and all losses, damages, expenses, liabilities, claims and demands whatsoever made or brought against the Vendor by any person or Employee, association or trade union or by any federal, provincial, municipal or other government department, commission, board, bureau, agency or instrumentality or any other person or body which in any way pertains to or arises out of such liability including, without limiting the generality of the foregoing, any and all losses, damages, expenses, liabilities, claims and demands whatsoever with respect to wages, severance pay, notice of termination of employment or pay in lieu of such notice, damages for wrongful dismissal or other employee benefits or claims, including vacation pay, and including any interest, award, judgment or penalty relating thereto and any costs or expenses incurred by the Vendor in defending any such claim or demand.

6.5 **Local presence.** The Purchaser shall guarantee a local presence within the Vendor's office located at 70 Victoria Street, Simcoe, Ontario for a minimum period of 3 years. The Norfolk

Corporations' central operating facility and all operating Employees will be located or relocated to the Purchaser's Simcoe Operations Centre located at 4 Boswell Street or the location in Simcoe to which Purchaser relocates Dundas functions. The Purchaser shall also move its Dundas Field Business Centre functions from the City of Hamilton to the Town of Simcoe over a three (3) year period.

6.6 **Capital Program.** The Purchaser acknowledges and agrees that the aggregate capital expenditure budget and forecast for the Business is as set out in Schedule 6.6 hereto ("CapEx"), and agrees to use commercially best efforts to meet such CapEx.

6.7 **Rate Harmonization.**

(a) Notwithstanding Section 2.6, the Purchaser acknowledges, agrees and covenants to:

(i) within the timeframe specified in Section 7.1 and as part of the Required Approval, seek OEB approval for a negative rate rider ("Negative Rate Rider") to reduce Current Rates by 1% across all Rate classes (the "Reduced Rates"); and

(ii) such Reduced Rates shall:

(A) be effective as of the Closing Date; and

(B) be maintained without change during the Rate Freeze Period.

(b) If the OEB does not approve the Negative Rate Rider in accordance with subsection (a), the Purchaser acknowledges, agrees and covenants to maintain Rates at Current Rates during the Rate Freeze Period." For greater clarity, this subsection (b) shall not affect the obligations of the Purchaser under Section 2.6.

6.8 **Books and Records.** The Purchaser shall preserve the books and records delivered by the Vendor to it pursuant to Section 5.3 for a period of eight (8) years from the Closing Date, or for such longer period as is required by any Applicable Law, and will permit the Vendor or its authorized Representatives reasonable access thereto in connection with the affairs of the Vendor relating to its matters.

6.9 **Ancillary Agreements.** The Purchaser hereby covenants and agrees that on the Closing Date, the Purchaser shall enter into the following agreement ("Ancillary Agreement"):

(a) an agreement for the purchase and sale, whereby NPDI shall sell, and the Vendor shall purchase, effective as of the Closing Date, certain trans poles for a fixed cost per pole (the "Pole Purchase and Sale Agreement"), the terms and conditions for which are contained substantially in the form of agreement attached hereto as Exhibit 6.9.

6.10 **Confidentiality.**

(a) Vendor hereby covenants and agrees that it shall keep confidential and not use or disclose except as required by Applicable Law, any and all information received by the Vendor from the Purchaser leading up to or in connection with the execution of this Agreement and completion of the transactions contemplated hereby, whether or not received prior to or after the Effective Date, concerning the business and affairs of the Purchaser or its Affiliates.

(b) In the event that this Agreement is terminated in accordance with the provisions hereof,

(i) the Purchaser hereby covenants and agrees that it, and its Affiliates, shall keep confidential, in accordance with the terms of the Confidentiality Agreement, any and all information and trade secrets received by the Purchaser from the Vendor, whether or not received prior to or after the date of this Agreement, concerning the business and affairs of the Vendor and/or the Norfolk Corporations (the "Confidential Information").

(ii) subject to paragraph (ii), the Purchaser shall:

(A) promptly return to the Vendor all documents, computer disks, other forms of electronic storage or other materials furnished by the Vendor, or the Norfolk Corporations or by any of their respective Representatives to the Purchaser or its Representatives constituting Confidential Information, together with all copies and summaries thereof in the possession or under the control of the Purchaser or its Representatives and materials generated by the Purchaser or its Representatives that include or refer to any part of the Confidential Information, without retaining a copy of any such material; or

(B) alternatively, provided that the prior written consent of the Vendor has been obtained, promptly destroy all documents or other matters constituting Confidential Information in the possession or under the control of the Purchaser or its Representatives;

and the Purchaser shall confirm such return and/or destruction of Confidential Information to the Vendor in writing and certified by two senior officers of the Purchaser;

(iii) the Purchaser shall promptly destroy the portion of the Confidential Information which consist of analyses, compilations, forecasts, studies, other material or documents prepared by the Purchaser or its Representatives and shall confirm such destruction in writing and certified by two senior officers of the Purchaser;

(iv) any verbal or visual Confidential Information will continue to be subject to the terms of the Confidentiality Agreement and the terms of this Section 6.1; and

(v) the Purchaser shall not, directly, use for its own purposes, any Confidential Information discovered or acquired by the Purchaser's Representatives as a result of the Vendor, or the Norfolk Corporations making available to them any Confidential Information.

6.11 **Survival.** The covenants contained in this Article VI shall survive the Closing Date.

ARTICLE VII
REQUIRED APPROVAL

7.1 **OEB Approval.** Each of the Purchaser and the Vendor shall as promptly as practicable after the execution of this Agreement (but in no event later than fifteen (15) days after the execution of this Agreement), file or cause to be filed with the OEB an application required to be made under Subsection 86(2) of the OEB Act in respect of the OEB Approval as it relates to NPDI (the "**Required Approval**"). Each of the Purchaser and the Vendor shall use their best efforts (which shall not be less than commercially reasonable efforts) to co-operate and assist the other, so that the Required Approval can be obtained as soon as reasonably possible, and in any event prior to the Closing Date. All the costs and expenses incurred by the Parties in connection with the application for the OEB Approval shall be borne each Party.

7.2 **Ontario Minister of Finance Notice.** The Vendor shall as promptly as practicable after the execution of this Agreement (but in no event later than the day before the Closing Date), file or cause to be filed with the Ontario Minister of Finance the notification required under Subsection 4(2) of Ontario Regulation 124/99 made under the EA. If necessary, the Vendor will also file or cause to be filed with the Ontario Minister of Finance such notification as required by Section 7 of Ontario Regulation 124/99 within thirty (30) days after the Closing Date. The Purchaser shall be responsible for the costs incurred by it in connection with the Ontario Minister of Finance Notice.

7.3 **Environmental Permits.** The Parties shall co-operate to ensure promptly that any required notices of change are given with respect to all Environmental Approvals, if any.

ARTICLE VIII
TAX MATTERS

8.1 **Preparation and Filing of Tax Returns**. The Purchaser shall cause the Corporation to prepare and submit all Tax Returns of each Norfolk Corporation that are not due for filing until after the Closing Date to the Vendor for approval at least thirty (30) Business Days before the filing due-date thereof except for the debt retirement charge and sales tax returns, which shall be prepared and submitted to the Vendor for approval at least seven (7) Business Days before the filing due-date thereof . The Purchaser shall provide the Vendor and its Representatives access to such Books and Records of the Norfolk Corporations relating to the period preceding Closing as the Vendor reasonably request for purposes of approving those Tax Returns. After the Vendor has approved those Tax Returns, the Purchaser shall, on a timely basis, cause each Norfolk Corporation to file the Tax Returns.

8.2 **Books and Records Relating to Taxes**. Within thirty (30) Business Days after the Closing Date, the Vendor shall deliver to the Purchaser the copies of all documents relating to Taxes of the Corporation in respect of the period preceding Closing that the Vendor retained pursuant to Section 5.3(b) and all working papers, correspondence and other documents prepared after the Closing Date which relate to Taxes for such periods.

8.3 **Notification Requirements**. The Purchaser shall promptly forward to the Vendor all written notifications and other written communications from any Governmental Authority received by the Purchaser or the Norfolk Corporations relating to Taxes of the Norfolk Corporations for all periods preceding Closing, and shall promptly inform the Vendor of any audit proposed to be undertaken and any adjustment proposed in writing to be made by any Governmental Authority in respect of a Pre-Closing Period. Notwithstanding the obligation of the Purchaser to give prompt notice as required above, the failure of the Purchaser to give that prompt notice shall not relieve the Vendor of its obligations under this Article VIII except to the extent (if any) that the Vendor shall have been prejudiced thereby.

8.4 **Vendor Indemnification**. From and after the Closing Date, the Vendor shall be responsible for and shall indemnify and save harmless the Purchaser for all Taxes payable by the Norfolk Corporations for all periods preceding Closing, less any Tax refunds and credits received by the Norfolk Corporations after the Closing Date and where such Tax refunds and credits relate to periods preceding Closing.

8.5 **Purchaser's Contest Rights**. Subject to Section 8.6, the Purchaser shall have the sole right to control, defend, settle, compromise, or prosecute in any manner an audit, examination, investigation, and other proceeding with respect to any Tax Return of the Norfolk Corporations. The Purchaser shall keep the Vendor duly informed of any proceedings in connection with any matter for which the Purchaser may have a right to indemnification pursuant to this Article VIII or Article XII and promptly provide the Vendor with copies of all correspondence and documents relating to those proceedings. The Vendor shall execute or cause to be executed such documents and shall take such action as reasonably requested by the Purchaser to enable the Purchaser to take any action the Purchaser deems appropriate with respect to any proceedings in respect of which the Purchaser has contest rights under this Agreement.

8.6 **Vendor's Contest Rights**.

(a) The Vendor may at any time by written notice to the Purchaser elect to control, defend, settle, compromise or prosecute in any manner an audit, examination, investigation, or other proceeding with respect to Taxes or Tax issues related to any matter in respect of which the Purchaser may have a right of indemnification pursuant to this Article VIII or Article XII, except that:

(i) the Vendor shall deliver to the Purchaser a written agreement that the Purchaser is entitled to indemnification for all Losses arising out of that audit, examination or other proceeding and that the Vendor shall be liable for the entire amount of those Losses;

(ii) the Vendor may not, without the written consent of the Purchaser, settle or compromise Taxes or Tax issues related to any matter which may affect Tax liabilities of the Purchaser or the Norfolk Corporations for a period following Closing; and

(iii) the Vendor shall pay to the Purchaser the amount of all Taxes (including, for greater certainty, interest and penalties) specified in the notice of assessment or other Claim from the Governmental Authority which are due and payable and to which the Purchaser's indemnity Claim relates within 10 Business Days before the amount is required to be paid to the Governmental Authority or within 10 Business Days after the Purchaser has forwarded to the Vendor a Claim for indemnity.

(b) If the consent of the Purchaser to a settlement or compromise arranged by the Vendor is not obtained for any reason, the indemnification liability of the Vendor shall be limited to the proposed settlement amount. The Purchaser and/or the Norfolk Corporations, as applicable, shall execute or cause to be executed such documents or take such action as reasonably requested by the Vendor to enable the Vendor to take any action it deems appropriate with respect to any proceedings in respect of which the Vendor has contest rights under this Agreement. In addition:

(i) the Vendor shall keep the Purchaser duly informed of any proceedings in connection with any matter which may affect the Taxes payable by the Purchaser or the Norfolk Corporations; and

(ii) the Purchaser shall be promptly provided with copies of all correspondence and documents relating to those proceedings and may, at its option and its own expense, participate in those proceedings through counsel of its choice.

8.7 **Indemnification Procedures**. Except to the extent expressly provided to the contrary in this Article VIII, the general procedures regarding notice and pursuit of indemnification Claims set forth in Article XII shall apply to all Claims for indemnification made under this Article VIII, except that notwithstanding any provision of Article XII to the contrary, if a Claim for indemnification involves any matter covered in this Article VIII, then the contest provisions of Sections 8.5 and 8.6, as applicable, shall control regarding the defence and handling of any such third-party Claim that could give rise to an indemnification obligation on the part of the Vendor. Notwithstanding Article IV, there shall be no limit on the time period during which a Claim for indemnification may be made under this Article VIII.

ARTICLE IX
CONDITIONS OF CLOSING

9.1 **Conditions of Closing in Favour of the Purchaser.** The Transaction including sale and purchase of the Purchased Shares are subject to the following conditions for the exclusive benefit of the Purchaser, to be fulfilled or performed at or prior to the Time of Closing:

(a) **Representations and Warranties** - The representations and warranties of the Vendor contained in this Agreement which are qualified as to materiality shall be true and correct and those not qualified as to materiality shall be true and correct in all material respects at the Time of Closing, with the same force and effect as if such representations and warranties were made at and as of such time, and a certificate of (i) the Mayor; and (ii) the Clerk, or the Deputy Clerk of the Vendor dated the Closing Date to that effect shall have been delivered to the Purchaser.

(b) **Covenants** - All of the obligations, covenants and agreements contained in this Agreement to be complied with or performed by the Vendor at or prior to the Time of Closing shall have been complied with or performed, and a certificate from (i) the Mayor; and (ii) the Clerk, or the Deputy Clerk of the Vendor dated the Closing Date to that effect shall have been delivered to the Purchaser.

(c) **Consents and Required Approval** - There shall have been obtained, from all appropriate Persons the Required Approval.

(d) **No Action to Restrain** - No order of any court of competent jurisdiction or administrative agency shall be in existence and, no action or proceeding shall be pending or threatened in writing by any Person, to restrain or prohibit:

   (i) the purchase and sale of the Purchased Shares; or

   (ii) the Norfolk Corporations from carrying on the Business as the Business is being carried on as at the date hereof;

(e) **Material Adverse Effect** - There shall not have occurred any change to the Business or change of Applicable Law which would have a Material Adverse Effect since the date of this Agreement.

(f) **Resignation of Directors** - All directors of the Norfolk Corporations shall have tendered their resignations and each such individual and the Vendor shall have duly executed and delivered comprehensive releases of all their claims (other than in respect of unpaid salaries and accrued vacation pay) respectively against the Norfolk Corporations.

(g) **Financial Statements**. Within fourteen (14) days of delivery of the Financial Statements by the Vendor to the Purchaser, the Purchaser shall provide written notice to the Vendor identifying Material Discrepancies, if any. The Vendor shall use commercially reasonable efforts to rectify any Material Discrepancies identified by the Purchaser in the written notice any time prior to Closing, to the Purchaser's satisfaction acting reasonably. Upon rectification of the Material Discrepancies by the Vendor or if the Purchaser does not provide written notice within the time frame specified herein, the Purchaser's rights under this section shall expire and the Vendor's obligations hereunder shall terminate.

If any of the conditions contained in this Section 9.1 shall not be performed or fulfilled at or prior to the Time of Closing or any other timeframe specified above to the satisfaction of the Purchaser, acting reasonably, the Purchaser may, by notice to the Vendor, terminate this Agreement and the obligations of the Vendor and the Purchaser under this Agreement and in such event the Purchaser shall be released from all obligations hereunder except those set forth in Section 6.1 and in the Confidentiality Agreement and the Vendor shall refund the Deposit, as the Purchaser's sole and exclusive remedy for all matters arising out of this Agreement and Vendor shall be released from all obligations hereunder. Any such condition may be waived in whole or in part by the Purchaser without prejudice to any claims it may have for breach of covenant, representation or warranty.

9.2 **Conditions of Closing in Favour of the Vendor.** The purchase and sale of the Purchased Shares is subject to the following terms and conditions for the exclusive benefit of the Vendor, to be fulfilled or performed at or prior to the Time of Closing:

(a) **Representations and Warranties** - The representations and warranties of the Purchaser contained in this Agreement which are qualified as to materiality shall be true and correct and those not qualified as to materiality shall be true and correct in all material respects at the Time of Closing, with the same force and effect as if such representations and warranties were made at and as of such time, and a certificate of two (2) senior officers of the Purchaser dated the Closing Date to that effect shall have been delivered to the Purchaser.

(b) **Covenants** – All of the obligations, covenants, and agreements contained in this Agreement to be complied with or performed by the Purchaser at or prior to the Time of Closing shall have been complied with or performed, and a certificate of two (2) senior officers of the Purchaser dated the Closing Date to that effect shall have been delivered to the Vendor.

(c) **Consents and Regulatory Approvals** - There shall have been obtained, from all appropriate Persons such consents, as may be required in connection with the completion of the Transaction, including without limitation, the Required Approval.

(d) **Ancillary Agreements** - The Purchaser and Vendor shall have entered into the Ancillary Agreement in substantially as the form attached to this Agreement.

(e) **No Action to Restrain** - No order of any court of competent jurisdiction or administrative agency shall be in existence and, no action or proceeding shall be pending or threatened in writing by any Person, to restrain or prohibit the purchase of the Purchased Shares.

If any of the conditions in this Section 9.2 shall not be performed or fulfilled at or prior to the Time of Closing to the satisfaction of the Vendor, acting reasonably, the Vendor may, by notice to the Purchaser, terminate this Agreement and the obligations of the Vendor and the Purchaser under this Agreement, and in such event the Vendor shall be released from all obligations hereunder except those set forth in the Confidentiality Agreement and the Vendor shall be entitled to the Deposit only in circumstances resulting in termination for failure of performance or fulfillment by the Purchaser of the conditions listed in Section 9.2 (a) and (b), as its sole and exclusive remedy for all matters arising out of this Agreement and Purchaser shall be released from all obligations hereunder. Any such condition may be waived in whole or in part by the Vendor without prejudice to any claims it may have for breach of covenant, representation or warranty.

ARTICLE X
CLOSING ARRANGEMENTS

10.1 **Place of Closing.** The closing shall take place at the Time of Closing at the offices of Borden Ladner Gervais LLP, counsel to the Vendor, at Toronto, Ontario.

10.2 **Transfer.** At the Time of Closing, upon fulfilment of all the conditions set out in Article IX that have not been waived in writing by the Purchaser or the Vendor, the Vendor shall deliver to the Purchaser certificates representing all the Purchased Shares, duly endorsed in blank for transfer and will cause transfers of such shares to be duly and regularly recorded in the name of the Purchaser whereupon, subject to all other terms and conditions hereof being complied with, payment of the Purchase Price shall be paid and satisfied in the manner provided in Article II.

ARTICLE XI
ARBITRATION

11.1 **Arbitration.**

(a) Any dispute, controversy or claim arising out of or in connection with, or relating to, this Agreement, including the Confidentiality Agreement, or the performance, breach, termination or validity thereof, shall be finally settled by arbitration. Either Party may initiate arbitration within a reasonable time after any such dispute, controversy or claim has arisen, by delivering a written demand for arbitration upon the other Party. The arbitration shall be conducted in accordance with the Ontario *Arbitration Act*, S.O., 1991, c.17. The arbitration shall take place in Toronto, Ontario, and shall be conducted in English.

(b) The arbitration shall be conducted by a single arbitrator having no financial or personal interest in the outcome of the arbitration. The arbitrator shall be appointed jointly by agreement of the Parties. In the event the Parties are unable to agree on the appointment of the arbitrator within ten (10) days after notice of a demand for arbitration is given by either Party, then either Party shall be free to apply to the Superior Court of Ontario for an Order appointing the arbitrator. Absent agreement or an award in the arbitration to the contrary, the arbitration fees and expenses shall be paid by the Parties jointly.

(c) The arbitrator shall have the authority to award any remedy or relief that a court could order or grant in accordance with this Agreement, including, without limitation, specific performance of any obligation created under this Agreement, the issuance of an interim, interlocutory or permanent injunction, or the imposition of sanctions for abuse or frustration of the arbitration process.

(d) The arbitral award shall be in writing, stating the reasons for the award and be final and binding on the Parties with no rights of appeal. The award may include an award of costs, including reasonable legal fees and disbursements and fees and expenses of the arbitrator. Judgment upon the award may be entered by any court having jurisdiction thereof or having jurisdiction over the relevant Party or its assets.

ARTICLE XII
INDEMNIFICATION

12.1 **Indemnification for breaches of Covenants, Warranty, etc.** Subject to Sections 12.3 and 12.8, the Vendor covenants and agrees to indemnify and save harmless the Purchaser, and the Corporation effective as and from the Closing Time, from and against all Claims which may be made or brought against the Purchaser (or made or brought by the Purchaser against the Vendor pursuant to this Agreement) or any of the Norfolk Corporations and all Damages and Losses arising in connection therewith. The foregoing obligation of indemnification in respect of such Claims shall be subject to:

(a) the limitation contained in Section 4.1 respecting the survival of the representations and warranties of the Parties; and

(b) the requirement that the Vendor shall, in respect of any Claim made by any third Person, be afforded an opportunity at its sole expense to resist, defend and compromise such Claim.

12.2 **Indemnification by the Purchaser.** Subject to Section 12.3 and 12.8, the Purchaser agrees to indemnify and save harmless the Vendor from all Losses suffered or incurred by the Vendor as a result of or arising directly or indirectly out of or in connection with:

(a) any breach by the Purchaser of or any inaccuracy of any representation or warranty contained in this Agreement or in any agreement, instrument, certificate or other document delivered pursuant hereto;

(b) any breach or non-performance by the Purchaser of any covenant to be performed by it that is contained in this Agreement or in any agreement, certificate or other document delivered pursuant hereto in respect of which the Vendor or its respective officers, directors and employees and any of its respective agents, counsel or consultants involved in the due diligence investigations related to this transaction did not have knowledge of such breach or non-performance at any time prior to the Time of Closing; and

(c) the operations of the Business and the ownership of the Purchased Shares in respect of the period after the Closing Time.

12.3 **Notice of Claim.** In the event that a party (the "Indemnified Party") shall become aware of any Claim in respect of which the other party (the "Indemnifying Party") agreed to indemnify the Indemnified Party pursuant to this Agreement, the Indemnified Party shall promptly give written notice thereof to the Indemnifying Party. Such notice shall specify whether the Claim arises as a result of a claim by a person against the Indemnified Party (a "Third Party Claim") or whether the Claim does not so arise (a "Direct Claim"), and shall also specify with reasonable particularity (to the extent that the information is available):

(a) the factual basis for the Claim; and

(b) the amount of the Claim, if known.

If, through the fault of the Indemnified Party, the Indemnifying Party does not receive notice of any Claim in time to effectively contest the determination of any liability susceptible of being contested, the Indemnifying Party shall be entitled to set off against the amount claimed by the Indemnified Party the amount of any Losses incurred by the Indemnifying Party resulting from the Indemnified Party's failure to give such notice on a timely basis.

12.4 **Direct Claims.** With respect to any Direct Claim, following receipt of notice from the Indemnified Party of the Claim, the Indemnifying Party shall have 30 days to make such investigation of the Claim as is considered necessary or desirable. For the purpose of such investigation, the Indemnified Party shall make available to the Indemnifying Party the information relied upon by the Indemnified Party to substantiate the Claim, together with all such other information as the Indemnifying Party may reasonably request. If both parties agree at or prior to the expiration of such 30-day period (or any mutually agreed upon extension thereof) to the validity and amount of such Claim, the Indemnifying Party shall immediately pay to the Indemnified Party the full agreed upon amount of the Claim, failing which the matter shall be referred to binding arbitration in such manner as the parties may agree or shall be determined by a court of competent jurisdiction.

12.5 **Third Party Claims.** With respect to any Third Party Claim, the Indemnifying Party shall have the right, at its expense, to participate in or assume control of the negotiation, settlement or defence of the Claim and, in such event, the Indemnifying Party shall reimburse the Indemnified Party for all the Indemnified Party's out-of-pocket expenses as a result of such participation or assumption. If the Indemnifying Party elects to assume such control, the Indemnified Party shall have the right to participate in the negotiation, settlement or defence of such Third Party Claim and to retain counsel to act on its behalf, provided that the fees and disbursements of such counsel shall be paid by the Indemnified Party unless the Indemnifying Party consents to the retention of such counsel or unless the named parties to any action or proceeding include both the Indemnifying Party and the Indemnified Party and a representation of both the Indemnifying Party and the Indemnified Party by the same counsel would be inappropriate due to the actual or potential differing interests between them (such as the availability of different defences). If the Indemnifying Party, having elected to assume such control, thereafter fails to defend the Third Party Claim within a reasonable time, the Indemnified Party shall be entitled to assume such control and the Indemnifying Party shall be bound by the results obtained by the Indemnified Party with respect to such Third Party Claim. If any Third Party Claim is of a nature such that the Indemnified Party is required by applicable Law to make a payment to any person (a "Third Party") with respect to the Third Party Claim before the completion of settlement negotiations or related legal proceedings, the Indemnified Party may make such payment and the Indemnifying Party shall, forthwith after demand by the Indemnified Party, reimburse the Indemnified Party for such payment. If the amount of any liability of the Indemnified Party under the Third Party Claim in respect of which such a payment was made, as finally determined, is less than the amount that was paid by the Indemnifying Party to the Indemnified Party, the Indemnified Party shall, forthwith after receipt of the difference from the Third Party, pay the amount of such difference to the Indemnifying Party.

12.6 **Settlement of Third Party Claims.** If the Indemnifying Party fails to assume control of the defence of any Third Party Claim, the Indemnified Party shall have the exclusive right to contest, settle or pay the amount claimed. Whether or not the Indemnifying Party assumes control of the negotiation, settlement or defence of any Third Party Claim, the Indemnifying Party shall not settle any Third Party Claim without the written consent of the Indemnified Party, which consent shall not be unreasonably withheld or delayed; provided, however, that the liability of the Indemnifying Party shall be limited to the proposed settlement amount if any such consent is not obtained for any reason.

12.7 **Co-Operation.** The Indemnified Party and the Indemnifying Party shall co-operate fully with each other with respect to Third Party Claims, and shall keep each other fully advised with respect thereto (including supplying copies of all relevant documentation promptly as it becomes available).

12.8 **Limitation on Claims.**

(a) Notwithstanding Sections 12.1 and 12.2 or any other provision in this Agreement:

(i) no Claim for indemnification hereunder may be made by the Purchaser against the Vendor until the aggregate amount of Claims in respect of which the Purchaser may so claim exceeds ten million dollars ($10,000,000) (the "Deductible"), and then only for the amount of any Claims exceeding the Deductible;

(ii) the maximum aggregate amount of indemnification exceeding the Deductible which may be payable by the Vendor under this Agreement shall not exceed an aggregate of ten million dollars ($10,000,000), for any reason whatsoever; and

(iii) if any payment made pursuant to this Article XII is subject to HST or is deemed by Applicable Law to be inclusive of HST, the Indemnifying Party shall pay to the Indemnified Party an amount equal to the HST in connection with the payment and any additional amount hereunder.

(b) Neither Party shall be required to indemnify or save harmless the other Party in respect of any breach or inaccuracy of any representation or warranty made under Article III unless notice is provided by the Indemnified Party to the Indemnifying Party in accordance with Section 12.1 on or prior to the expiration of the applicable time period related to such representation and warranty as set out in Article XII.

(c) The Indemnifying Party shall only be liable for Losses suffered by the Indemnified Party in respect of a Claim after taking into account:

(i) insurance proceeds received by the Indemnified Party in respect of the occurrence giving rise to the Claim; and

(ii) Tax benefits accruing to the Indemnified Party relating to the actions taken by the Indemnified Party in respect of the Claim.

12.9 **Exclusivity.** The provisions of this Article XII shall apply to any Claim for or in respect of any breach of any covenant, representation, warranty, indemnity or other provision of this Agreement or any agreement, certificate or other document delivered pursuant to this Agreement (other than a claim for specific performance or injunctive relief) with the intent that all such Claims shall be subject to the limitations and other provisions contained in this Article XI.

ARTICLE XIII
MISCELLANEOUS

13.1 **Further Assurances.** Each Party to this Agreement covenants and agrees that, from time to time subsequent to the Closing Date, it will, at the request and expense of the requesting Party, execute and deliver all such documents, including, without limitation, all such additional conveyances, transfers, consents and other assurances and do all such other acts and things as any other party hereto, acting reasonably, may from time to time request be executed or done in order to better evidence or perfect or effectuate any provision of this Agreement or of any agreement or other document executed pursuant to this Agreement or any of the respective obligations intended to be created hereby or thereby.

13.2 **Announcements.** The Parties shall make a joint public announcement with respect to this Agreement and the transactions herein contemplated, at such time and in such manner as may be mutually agreed upon by the Parties. Except as required by law, no other public announcement, press release, notices, statements and communications to third parties shall be made by either Party hereto without the prior consent and approval of the other Party, provided that the Parties hereby acknowledge that the Parties may be compelled to disclose details of this Agreement and the transactions contemplated herein in respect of the OEB Approval and that the Vendor or the Purchaser may be compelled to disclose details of this agreement and the transactions herein contemplated pursuant to the *Municipal Freedom of Information and Protection of Privacy Act* (Ontario).

13.3 **Brokerage, Commissions, etc.** It is understood and agreed that no broker, agent or other intermediary has acted for the Vendor, the Corporation or the Purchaser, in connection with the transaction herein contemplated. The Vendor agrees to indemnify and save harmless the Purchaser from and against any claim for commission or other remuneration payable or alleged to be payable to any broker, agent or other intermediary who purports to act or to have acted for the Vendor in connection with the transactions herein contemplated. The Purchaser agrees to indemnify and save harmless the Vendor from and against any claim for commission or other remuneration payable or alleged to be payable to any broker, agent or other intermediary, who purports to act or to have acted for the Purchaser in connection with the transactions herein contemplated.

13.4 **Notices.**

(a) Any notice or other communication required or permitted to be given hereunder shall be in writing and shall be delivered in person, transmitted by telecopy or sent by registered mail, charges prepaid, addressed as follows:

(i) if to the Vendor:

The Corporation of Norfolk County
50 Colborne Street, South
Simcoe, ON
N3Y 4H3

Attention: Municipal Clerk

Fax No.: 519.426.8573

(ii) if to the Purchaser:

Hydro One Inc.
483 Bay Street
Toronto, ON M5G 2P5

Attention: General Counsel

Fax No.: 416-345-6056

(b) Any such notice or other communication shall be deemed to have been given and received on the day on which it was delivered or transmitted (or, if such day is not a Business Day, on the next following Business Day) or, if mailed, on the third Business Day following the date of mailing; provided, however, that if at the time of mailing or within three Business Days thereafter there is or occurs a labour dispute or other event that might reasonably be expected to disrupt the delivery of documents by mail, any notice or other communication hereunder shall be delivered or transmitted by telecopy as aforesaid.

(c) Either Party may at any time change its address for service from time to time by giving notice to the other parties in accordance with this Section 12.4.

13.5 **Best Efforts.** The Parties acknowledge and agree that, for all purposes of this Agreement, an obligation on the part of the Party to use its best efforts (which shall not be less than commercially reasonable efforts) to obtain any waiver, consent, approval, permit, licence or other document shall not require such Party to make any payment to any person for the purpose of procuring the same, other than payments for amounts due and payable to such person, payments for incidental expenses incurred by such person and payments required by any applicable law or regulation.

13.6 **Costs and Expenses.** Except as otherwise provided for herein, all costs and expenses (including, without limitation, the fees and disbursements of legal counsel) incurred in connection with this Agreement and the transactions herein contemplated shall be paid by the Party incurring such costs and expenses.

13.7 **Counterparts.** This Agreement may be executed in counterparts, each of which shall constitute an original and all of which taken together shall constitute one and the same instrument.

IN WITNESS WHEREOF this Agreement has been executed by the parties.

THE CORPORATION OF NORFOLK COUNTY

By:
Name: Dennis Travale
Title: Mayor

HYDRO ONE INC.

By:
Name: Carmine Marcello
Title: President and Chief Executive Officer

SCHEDULE 1.11.1(GG) – DRAFT FINANCIAL STATEMENTS

Norfolk Energy Inc.

Balance Sheet

As at December 31, 2012

	2012	2011
ASSETS		
Current		
Cash	$ 324,180	$ 129,271
Term deposits	2,250,000	-
Accounts receivable	51,211	215,778
Inventory	-	1,032
Income taxes recoverable	-	52,419
	2,625,391	398,500
Property and equipment *(Note 4)*	1,225,713	2,542,368
	$ 3,851,104	$ 2,940,868
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable	$ 228,414	$ 176,038
Income taxes payable	406,628	-
Due to associated companies *(Note 5)*	1,906,880	133,145
Deferred revenue	63,991	168,715
Current portion of bank loan	-	58,333
	2,605,913	536,231
Bank loan *(Note 6)*	-	500,695
Future income taxes	94,000	118,000
	2,699,913	1,154,926
Shareholder's equity		
Share capital *(Note 7)*	373,386	373,386
Retained earnings	777,805	1,412,556
	1,151,191	1,785,942
	$ 3,851,104	$ 2,940,868

Norfolk Energy Inc.

Statement of Retained Earnings

Year ended December 31, 2012

	2012	2011
Retained earnings - beginning of year	**$ 1,412,556**	$ 1,306,405
Net income for the year	**1,165,249**	146,151
	2,577,805	1,452,556
Dividends	**(1,800,000)**	(40,000)
RETAINED EARNINGS - END OF YEAR	**$ 777,805**	$ 1,412,556

Norfolk Energy Inc.

Statement of Operations

Year ended December 31, 2012

	2012	2011
REVENUE - Schedule 1	**$ 2,273,343**	$ 1,867,240
EXPENSES - Schedule 1	**84,750**	815,032
NET REVENUE	**2,188,593**	1,052,208
OTHER EXPENSES		
Administrative and general expense	**348,181**	509,798
Income before amortization, interest and taxes	**1,840,412**	542,410
Amortization	**211,572**	314,909
Interest	**38,217**	29,532
	249,789	344,441
Income before income taxes	**1,590,623**	197,969
Income taxes		
Current *(Note 8)*	**449,374**	46,818
Future	**(24,000)**	5,000
	425,374	51,818
NET INCOME FOR THE YEAR	**$ 1,165,249**	$ 146,151

Norfolk Energy Inc.

Schedule of Revenue and Expenses *(Schedule 1)*

Year Ended December 31, 2012

	Revenue	Expenses	**Net Revenue 2011**	Net Revenue 2010
Telecommunication services *(Note 9)*	$ 340,869	$ 57,602	**$ 283,267**	$ 258,410
Home comfort division *(Note 9)*	389,397	24,206	**365,191**	509,227
Gain on sale of home comfort division *(Note 9)*	1,523,922	-	**1,523,922**	-
Interest and sundry revenue	955	-	**955**	(39,308)
Sentinel light rentals *(Note 9)*	18,200	2,942	**15,258**	22,142
Billing and collecting services *(Note 9)*	-	-	**-**	161,586
Conservation program consulting *(Note 9)*	-	-	**-**	115,881
SCADA services *(Note 9)*	-	-	**-**	6,523
Street light maintenance *(Note 9)*	-	-	**-**	17,747
	$ 2,273,343	$ 84,750	**$ 2,188,593**	$ 1,052,208

Norfolk Energy Inc.

Statement of Cash Flow

Year ended December 31, 2012

	2012	2011
OPERATING ACTIVITIES		
Net income for the year	**$ 1,165,249**	$ 146,151
Items not affecting cash:		
Amortization	**211,572**	314,909
Future income taxes	**(24,000)**	5,000
(Gain) loss on disposal of property and equipment	**(1,506,532)**	48,545
	(153,711)	514,605
Changes in non-cash working capital:		
Accounts receivable	**164,567**	(10,949)
Inventory	**1,032**	21,315
Income taxes recoverable	**459,047**	(42,223)
Accounts payable	**52,376**	59,785
Due to associated companies	**1,773,735**	(26,645)
Deferred revenue	**(104,724)**	66,610
	2,346,033	67,893
Cash flow from operating activities	**2,192,322**	582,498
INVESTING ACTIVITIES		
Purchase of property and equipment	**(434,274)**	(587,075)
Proceeds on disposal of property and equipment	**3,045,889**	9,874
Purchase of investments	**(2,250,000)**	-
Cash flow from (used by) investing activities	**361,615**	(577,201)
FINANCING ACTIVITIES		
Dividends paid	**(1,800,000)**	(40,000)
Repayment of bank loan	**(559,028)**	(58,333)
Cash flow used by financing activities	**(2,359,028)**	(98,333)
INCREASE (DECREASE) IN CASH	**194,909**	(93,036)
Cash - beginning of year	**129,271**	222,307
CASH - END OF YEAR	**$ 324,180**	$ 129,271

Printed: March 26, 2013 3:50 PM **Prep** _______ **Added** _______ **Approved** _______

NORFOLK ENERGY

Norfolk Power Distribution Inc.

Balance Sheet

As at December 31, 2012

	2012	2011
ASSETS		
Current		
Cash	**$ 895,049**	$ 3,142,592
Accounts receivable	**5,188,861**	4,253,675
Unbilled revenue	**4,062,418**	3,953,201
Due from associated companies *(Note 5)*	**39,571**	-
Income taxes recoverable	**-**	729,939
Inventory	**575,141**	533,619
Prepaid expenses	**390,613**	395,003
	11,151,653	13,008,029
Property and equipment *(Note 6)*	**53,859,407**	50,122,402
Regulatory assets *(Note 7)*	**1,249,684**	6,389,112
Future income taxes	**897,781**	897,781
	$ 67,158,525	$ 70,417,324
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable	**$ 5,396,838**	$ 6,707,499
Due to associated companies	**-**	134,166
Current portion of customer deposits	**50,000**	115,000
Current portion of long term debt	**1,172,547**	966,967
	6,619,385	7,923,632
Regulatory liabilities *(Note 7)*	**2,930,240**	4,259,651
Customer deposits *(Note 8)*	**51,547**	20,916
Long term debt *(Note 9)*	**26,997,457**	28,170,004
Post employment benefits *(Note 10)*	**956,214**	878,082
	37,554,843	41,252,285
Shareholder's equity		
Share capital *(Note 11)*	**22,768,898**	22,768,898
Retained earnings	**6,834,784**	6,396,141
	29,603,682	29,165,039
	$ 67,158,525	$ 70,417,324

See accompanying notes

Norfolk Power Distribution Inc.
Statement of Retained Earnings
Year ended December 31, 2012

	2012	2011
Retained earnings - beginning of year	**$ 6,396,141**	$ 4,885,948
Net income for the year	**1,638,643**	2,310,193
	8,034,784	7,196,141
Dividends	**(1,200,000)**	(800,000)
RETAINED EARNINGS - END OF YEAR	**$ 6,834,784**	$ 6,396,141

See accompanying notes

Norfolk Power Distribution Inc.

Statement of Operations

Year ended December 31, 2012

	2012	2011
REVENUE		
Energy sales	**$ 34,011,357**	$ 32,764,997
Distribution services	**11,424,687**	11,022,242
Other	**660,823**	667,005
	46,096,867	44,454,244
Cost of power	**34,011,357**	32,764,997
Distribution revenue	**12,085,510**	11,689,247
EXPENSES		
Distribution system - operation and maintenance	**2,245,690**	2,191,894
Billing and collecting	**1,251,412**	1,008,136
Community relations	**30,932**	48,570
Administrative and general expense	**2,732,838**	1,553,796
Taxes other than amounts in lieu of corporate taxes	**57,594**	36,435
	6,318,466	4,838,831
Income before amortization, interest and income taxes	**5,767,044**	6,850,416
Amortization *(Note 12)*	**2,308,080**	2,625,509
Interest	**1,402,550**	1,638,214
	3,710,630	4,263,723
Income before income taxes	**2,056,414**	2,586,693
Income taxes *(Note 13)*	**417,771**	276,500
NET INCOME FOR THE YEAR	**$ 1,638,643**	$ 2,310,193

See accompanying notes

Norfolk Power Distribution Inc.
Statement of Cash Flow
Year ended December 31, 2012

	2012	2011
OPERATING ACTIVITIES		
Net income for the year	$ 1,638,643	$ 2,310,193
Items not affecting cash:		
Amortization *(Note 12)*	2,408,371	2,949,756
Future income taxes	-	317,469
Post employment benefits	78,132	10,282
Loss (gain) on disposal of property and equipment	(6,600)	(13,890)
	4,118,546	5,573,810
Changes in non-cash working capital:		
Accounts receivable	(935,186)	(62,253)
Unbilled revenue	(109,217)	572,848
Amount due from (to) associated companies	(173,735)	216,647
Income taxes recoverable	729,939	(608,815)
Inventory	(41,522)	16,059
Prepaid expenses	4,390	(75,181)
Accounts payable	(1,310,661)	(1,242,123)
	(1,835,992)	(1,182,818)
Cash flow from operating activities	2,282,554	4,390,992
INVESTING ACTIVITIES		
Purchase of property and equipment	(7,132,954)	(5,053,411)
Proceeds on disposal of property and equipment	272,787	46,800
Contributions in aid of construction	721,389	1,338,253
Net change in regulatory assets and liabilities	3,810,017	(1,008,197)
Cash flow used by investing activities	(2,328,761)	(4,676,555)
FINANCING ACTIVITIES		
Repayment of customer deposits	(34,369)	(104,447)
Demand loan financing (repaid)	-	(3,500,000)
Loans and debentures financing received	-	6,000,000
Repayment of loans and debentures	(966,967)	(918,150)
Dividends declared	(1,200,000)	(800,000)
Cash flow from (used by) financing activities	(2,201,336)	677,403
INCREASE (DECREASE) IN CASH	(2,247,543)	391,840
Cash - beginning of year	3,142,592	836,521
CASH - END OF YEAR	$ 895,049	$ 1,228,361

See accompanying notes

SCHEDULE 2.3 – FORM OF ESCROW AGREEMENT

ESCROW AGREEMENT

THIS AGREEMENT dated this 2nd day of April, 2013 (the "**Effective Date**").

BETWEEN:

THE CORPORATION OF NORFOLK COUNTY

As Vendor

- and -

HYDRO ONE INC.

As Purchaser

- and -

BORDEN LADNER GERVAIS LLP

As Escrow Agent

RECITALS:

A. The Vendor and the Purchaser entered into a purchase agreement (the "**Purchase Agreement**") dated 28th of March, 2013 providing for the purchase and sale of all of the issued and outstanding shares of Norfolk Power Inc. (the "**Corporation**").

B. Pursuant to Section 2.3(a) of the Purchase Agreement, concurrently with the execution and delivery of the Purchase Agreement, the Purchaser shall deliver the Deposit to the Escrow Agent in trust and in accordance with the terms of this Agreement.

C. The preceding recitals and statements of fact are made by the Vendor and the Purchaser and not by the Escrow Agent.

IN CONSIDERATION of the mutual covenants and agreements contained in this Agreement and for other good and valuable consideration (the receipt and adequacy of which are acknowledged), the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions. In this Agreement, including the Recitals to this Agreement, capitalized terms not otherwise defined herein shall have the meaning ascribed thereto under the Purchase Agreement:

(1) "**Agreement**" means this escrow agreement as amended, supplemented, restated and replaced from time to time in accordance with its provisions.

(2) "**Escrow Agent**" means Borden Ladner Gervais LLP, a limited liability partnership duly constituted under the laws of the Province of Ontario.

(3) "**Parties**" means collectively the Vendor, the Purchaser and the Escrow Agent, and "**Party**" means any of them.

(4) "**Purchaser**" means Hydro One Inc., a corporation incorporated under the laws of Ontario;

(5) "**Purchase Agreement**" has the meaning attributed to that term in the Recitals.

(6) "**Vendor**" means The Corporation of Norfolk County, a municipal corporation incorporated under the laws of Ontario.

1.2 Certain Rules of Interpretation. In this Agreement:

(a) the division into Articles and Sections and the insertion of headings are for convenience of reference only and do not affect the construction or interpretation of this Agreement;

(b) the expressions "hereof", "herein", "hereto", "hereunder", "hereby" and similar expressions refer to this Agreement and not to any particular portion of this Agreement; and

(c) unless specified otherwise or the context otherwise requires:

(i) references to any Article, Section or Schedule are references to the Article or Section of, or Schedule to, this Agreement; and

(ii) words in the singular include the plural and vice-versa and words in one gender include all genders.

1.3 Performance on Business Days. If any action is required to be taken pursuant to this Agreement on or by a specified date that is not a Business Day, the action is valid if taken on or by the next succeeding Business Day.

1.4 Currency and Payment. In this Agreement, unless specified otherwise references to dollar amounts or "$" are to Canadian dollars.

ARTICLE 2
ESCROW

2.1 Appointment of Escrow Agent. The Vendor hereby appoints, and the Purchaser hereby concurs in the appointment of, the Escrow Agent to act as escrow agent, in accordance with the terms and conditions set out in this Agreement and the Escrow Agent hereby accepts that appointment.

2.2 **Delivery of Deposit into Escrow**. The Purchaser shall deliver the Deposit to the Escrow Agent on the date of this Agreement. The Escrow Agent shall hold and dispose of the Deposit in accordance with, and subject to the terms and conditions, of this Agreement.

2.3 **Interest on Deposit**. The Escrow Agent shall invest and retain the Deposit in its name, in a daily interest bearing account with any Canadian chartered bank listed on Schedule 1 of the *Bank Act* (Canada). At the Time of Closing, the Deposit and any and all interest accrued thereon (the "**Interest**") shall be paid by the Escrow Agent to the applicable party in accordance with Sections 2.4 and 2.5 of this Agreement.

2.4 **Release of Escrow Property and Interest**. The Escrow Agent shall retain the Deposit and Interest until the Time of Closing and upon the occurrence of this event, the Escrow Agent shall release the Deposit and Interest in accordance with the following:

(1) the joint written direction of the Purchaser and the Vendor to the Escrow Agent, and the Escrow Agent shall be entitled to act on such joint written direction; or

(2) if the parties are unable to provide such joint written direction, in accordance with Sections 3.5 and 3.6 of this Agreement.

2.5 **Joint Written Direction re Interest Payment.** For purposes of the joint written direction in Section 2.4(1), the Vendor and Purchaser shall determine and specify in the joint written direction the party that is entitled to the Deposit and/or Interest as of the Time of Closing, as follows:

(1) if the conditions set for in Article IX of the Purchase Agreement have been satisfied or complied with by each of the Vendor and Purchase, as applicable, or the Vendor or the Purchaser, as applicable, waives compliance therewith in whole or in part on such terms as may be agreed in writing, the Escrow Agent shall pay: (a) the Deposit to the Vendor; and (b) the Interest to the Purchaser; or

(2) if the conditions set forth in Section 9.1 of the Purchase Agreement have not been satisfied or complied with and the Purchaser does not waive compliance therewith in whole or in part on such terms as may be agreed in writing, the Deposit, together with any Interest earned thereon, but less any fees or costs payable by the Purchaser pursuant to Section 13.6 of the Purchase Agreement not yet then paid by the Purchaser, shall be refunded to the Purchaser; or

(3) if the transactions contemplated in the Purchase Agreement are not completed by the Closing Date and the conditions set forth in Section 9.2 therein have been satisfied, complied with or waived, the Deposit, together with any Interest earned thereon, shall be retained by the Vendor and applied by the Vendor against Losses suffered by the Vendor without limiting the Vendor's right to recover the balance of such Losses, if any.

2.6 **Termination of Escrow**. Upon the release and disbursement by the Escrow Agent of the all of the Deposit and Interest in accordance with the terms of this Agreement, this Agreement will terminate and be of no further force and effect, except to the extent necessary in order for Sections 3.3, 3.5, 3.6, 3.7 and 3.10 to continue to be of full force and effect, and the Escrow Agent will be automatically released from all of its duties and liabilities under this Agreement.

ARTICLE 3
CONCERNING THE ESCROW AGENT

3.1 Duties and Liability of Escrow Agent.

(1) The Escrow Agent has no duties other than those duties expressly set forth in this Agreement. The Escrow Agent will not refer to, and is not bound by, the provisions of any agreement other than the terms of this Agreement and no implied duties or obligations of the Escrow Agent may be read into this Agreement.

(2) Notwithstanding anything contained in this Agreement or in the Purchase Agreement to the contrary, the Escrow Agent has no duty to determine the performance or non-performance of any term or provision of the Purchase Agreement, has no obligation or responsibility to determine any dispute or evaluate any equities between the parties regardless of any knowledge or any fact that the Escrow Agent may have or receive, and has no obligations, responsibilities or liability arising under any other agreement to which the Escrow Agent is not a party, even though reference to such other agreement may be made in this Agreement or the Purchase Agreement.

(3) Nothing in this Agreement is to be construed as creating a relationship of trust between the Escrow Agent and the Vendor and Purchaser or either of them. The Vendor and the Purchaser understand and agree that the duties of the Escrow Agent under this Agreement are purely ministerial in nature and that the Escrow Agent is not liable for any error, judgement, or for any act done or step taken or omitted by it in good faith, or for any mistake of fact or law, or for anything which it may do or refrain from doing in connection herewith, except for its own fraud, gross negligence or wilful misconduct.

(4) The Escrow Agent is not under any duty to give the Deposit held by it under this Agreement any greater degree of care than it gives its own similar property. The Escrow Agent's duties with respect to delivery of the Deposit under this Agreement will be fully performed by delivering the Deposit and any Interest accrued thereon in accordance with Section 2.4.

(5) The appointment of the Escrow Agent is a personal one and the duty of the Escrow Agent is only to the other Parties, their successors and assigns, and to no other Person whomsoever.

3.2 Legal Counsel. The Escrow Agent has the right to consult with counsel of its own choice and is not be liable for any action taken, suffered or omitted to be taken by it if the Escrow Agent acts in accordance with the advice of such counsel.

3.3 Indemnity. The Purchaser and the Vendor hereby jointly and severally indemnify and shall save harmless the Escrow Agent from and against any and all actions, causes of action, claims, losses, demands, damages, expenses, costs, liabilities, penalties and expenses whatsoever and to reimburse the Escrow Agent for any legal or related expenses, including those of its own partners and associates (collectively, the "**Claims**") which the Escrow Agent, its partners, associates, employees and agents may suffer or incur in connection with its acting as Escrow Agent under this Agreement, other than Claims arising as a result of the fraud, gross negligence or wilful misconduct of the Escrow Agent in the performance of its duties under this Agreement. The Escrow Agent, its partners, associates, employees and agents will in no event be liable for any loss, Claim or indirect, consequential, incidental or punitive damages to either the Vendor or the Purchaser, regardless of whether or not such losses, claims or damages were reasonably foreseeable by the Escrow Agent.

3.4 Reliance.

(1) The Escrow Agent may:

(a) act in reliance on any writing or instrument or signature which it, in good faith, believes to be genuine;

(b) assume the validity and accuracy of any statement or assertion contained in such a writing or instrument; and

(c) assume that any Person purporting to give any written notice, advice or instructions on behalf of any of the other Parties in connection with the provisions of this Agreement has been duly authorized to do so.

The Escrow Agent is not, as such, liable in any manner for the sufficiency or correctness as to form, execution, or validity of any document, nor as to the identity, authority, or right of any Person executing the document.

(2) Nothing in this Agreement makes the Escrow Agent responsible, or liable in any manner for the sufficiency, correctness, genuineness or validity of any document forming part of the Deposit.

(3) The Escrow Agent is not required to make any determination or decision with respect to the validity of any claim made by any Party, or of any denial thereof but is entitled to rely conclusively on the terms of this Agreement and the documents tendered to it in accordance with the terms of this Agreement.

3.5 Disputes. If there is any dispute as to whether the Escrow Agent is obligated to deliver the Deposit and Interest, the Escrow Agent shall hold such Deposit and Interest until receipt of an authorization in writing executed by each of the Vendor and the Purchaser directing the delivery thereof, or in the absence of such authorization, the Escrow Agent may hold the Deposit and Interest until the final determination of the rights of the Parties in an appropriate court proceeding. If such written authorization is not given, or proceedings for such determination have not begun and been diligently continued, the Escrow Agent may bring, but is not required to bring, an appropriate action or proceeding pursuant to Section 3.6 for leave to deposit the Deposit and Interest in court, pending such determination. If a judicial proceeding is instituted by the Escrow Agent, the Escrow Agent will be entitled to reasonable solicitor's fees.

3.6 Interpleader. Without limiting Section 3.5, if:

(a) any action is threatened or instituted against the Escrow Agent;

(b) any dispute arises, or any action is threatened or instituted, concerning the entitlement of a Party to the Deposit and/or Interest; or

(c) if at any time the Escrow Agent is uncertain as to its obligations under this Agreement,

the Escrow Agent may apply to a court of competent jurisdiction in the Province of Ontario for clarification or directions with respect to its obligations under this Agreement, and in such event, or if any other person should apply to a court of competent jurisdiction (which must be in the Province of Ontario) on any matter affecting the obligations of the Escrow Agent under this Agreement or otherwise relating to the Deposit and/or Interest, the Escrow Agent may and is hereby authorized to release, deliver or otherwise deal with the Deposit and Interest in accordance with the directions, order, judgment or decree of such court.

3.7 Court Orders.

(1) The Escrow Agent is hereby authorized, in its sole discretion, to comply with all writs, orders or decrees entered or issued, whether with or without jurisdiction, which purport to:

(a) attach, garnish or be levied on any part of the Deposit and Interest;

(b) stay or enjoin the disbursement, payment or delivery of any part of the Deposit and Interest; or

(c) affect any part of the Deposit and Interest in any way.

The Escrow Agent is not liable to any of the other Parties or to any other Person because it obeys or complies with any such writ, order or decree, even if such writ, order or decree is subsequently reversed, modified, annulled, set aside or vacated.

3.8 No Disqualification. Each of the Vendor and the Purchaser acknowledges that the Escrow Agent:

(a) acts as counsel to the Vendor and may continue to act as counsel to Vendor in all matters including any matters in dispute between the Vendor and the Purchaser and any issue arising out of or in connection with this Agreement or the Deposit and Interest; and

(b) in so acting, is not disqualified from acting as Escrow Agent under this Agreement and is deemed not to be in conflict by reason of performing its duties under this Agreement.

3.9 **Resignation, Removal and Replacement of Escrow Agent**. The Escrow Agent may resign by notice to the other Parties. Upon the effective date of such resignation, the Escrow Agent shall deliver the Deposit and Interest then held by it under this Agreement to such Person as may be jointly designated in writing by the Vendor and the Purchaser as the new escrow agent (the "**Successor Escrow Agent**"). If the Vendor and the Purchaser fail to deliver such a written designation, the Escrow Agent will not resign its position until such designation is delivered or until the Deposit then held are delivered to the control of a court of competent jurisdiction. Upon the delivery of the Deposit to the Successor Escrow Agent or to the control of a court of competent jurisdiction, all of the Escrow Agent's obligations as escrow agent under this Agreement will cease and terminate.

ARTICLE 4
General

4.1 **Time of Essence**. Time is of the essence of this Agreement.

4.2 **Amendment**. This Agreement may be supplemented, amended, restated or replaced only by a written agreement signed by each Party.

4.3 **Waiver of Rights**. Any waiver of, or consent to depart from, the requirements of any provision of this Agreement is effective only if it is in writing and signed by the Party giving it, and only in the specific instance and for the specific purpose for which it has been given. No failure on the part of any Party to exercise, and no delay in exercising, any right under this Agreement operates as a waiver of such right. No single or partial exercise of any such right precludes any other or further exercise of such right or the exercise of any other right.

4.4 **Jurisdiction**. Each Party irrevocably and unconditionally attorns to the exclusive jurisdiction of the courts of the province of Ontario.

4.5 **Governing Law**. This Agreement and any dispute arising from or in relation to this Agreement is governed by, and interpreted and enforced in accordance with, the law of the Province of Ontario and the laws of Canada applicable in that Province, excluding the choice of law rules of that Province.

4.6 **Entire Agreement**. This Agreement constitutes the entire agreement between the Parties pertaining to the subject matter of this Agreement and supersedes all prior correspondence, agreements, negotiations, discussions and understandings, written or oral. There are no representations, warranties, conditions or other agreements or acknowledgements, whether direct or collateral, express or implied, written or oral, statutory or otherwise, that form part of or affect this Agreement or which induced any Party to enter into this Agreement. No reliance is placed on any representation, warranty, opinion, advice or assertion of fact made either prior to, concurrently with, or after entering into, this Agreement by any Party to this Agreement to any other Party, except to the extent the representation, warranty, opinion, advice or assertion of fact has been reduced to writing and included as a term in this Agreement and none of the Parties has been induced to enter into this Agreement or any amendment or supplement by reason of any such representation, warranty, opinion, advice or assertion of fact. There is no liability, either in tort or in contract, assessed in relation to the representation, warranty, opinion, advice or assertion of fact, except as contemplated in this Section.

4.7 Notices.

(1) Any notice, demand or other communication (in this Section 4.7, a "**notice**") required or permitted to be given or made under this Agreement must be in writing and is sufficiently given or made if:

(a) delivered in person and left with a receptionist or other responsible employee of the relevant Party at the applicable address set forth below;

(b) sent by prepaid courier service or (except in the case of actual or apprehended disruption of postal service) mail; or

(c) sent by facsimile transmission, with confirmation of transmission by the transmitting equipment (a "**Transmission**");

in the case of a notice to The Corporation of Norfolk County addressed to it at:

The Corporation of Norfolk County
50 Colborne Street, South
Simcoe, ON
N3Y 4H3

Attention: Municipal Clerk
Facsimile No.: 519.426.8573

Borden Ladner Gervais LLP
Scotia Plaza, 40 King Street West
Toronto, Ontario, Canada, M5H 3Y4

Attention: J. Mark Rodger, Partner
Facsimile No.: 416.361.7088

and in the case of a notice to Hydro One Inc., addressed to it at:

Hydro One Inc.
483 Bay Street
Toronto, Ontario, Canada, M5G 2P5

Attention: General Counsel
Facsimile No.: 416.345.6056

and in the case of a notice to Escrow Agent, addressed to it at:

Borden Ladner Gervais LLP
Scotia Plaza, 40 King Street West
Toronto, Ontario, Canada, M5H 3Y4

Attention: J. Mark Rodger, Partner
Facsimile No.: 416.361.7088

(2) Any notice sent in accordance with this Section 4.7 shall be deemed to have been received:

(a) if delivered prior to or during normal business hours on a Business Day in the place where the notice is received, on the date of delivery;

(b) if sent by mail, on the fifth Business Day in the place where the notice is received after mailing, or, in the case of disruption of postal service, on the fifth Business Day after cessation of such disruption;

(c) if sent by facsimile during normal business hours on a Business Day in the place where the transmission is received, on the same day that it was received by Transmission, on production of a Transmission report from the machine from which the facsimile was sent which indicates that the facsimile was sent in its entirety to the relevant facsimile number of the recipient; or

(d) if sent in any other manner, on the date of actual receipt;

except that any notice delivered in person or sent by Transmission not on a Business Day or after normal business hours on a Business Day, in each case in the place where the notice is received, shall be deemed to have been received on the next succeeding Business Day in the place where the notice is received.

(3) Any Party may change its address for notice by giving notice to the other Parties.

4.8 Assignment. No Party may assign or transfer, whether absolutely, by way of security or otherwise, all or any part of its rights or obligations under this Agreement to any Person without the prior written consent of the other Parties.

4.9 **Further Assurances**. Each Party shall, at the expense of another Party, promptly do, execute, deliver or cause to be done, executed or delivered all further acts, documents and matters in connection with this Agreement that such other Party may reasonably require, for the purposes of giving effect to this Agreement.

4.10 **Successors and Assigns**. This Agreement is binding on, and enures to the benefit of, the Parties and their respective heirs, administrators, executors, successors and permitted assigns.

4.11 **Counterparts**. This Agreement may be executed in any number of counterparts, each of which is deemed to be an original and all of which taken together constitutes one agreement. To evidence the fact that it has executed this Agreement, a Party may send a copy of its executed counterpart to all other Parties by Transmission and the signature transmitted by Transmission is deemed to be its original signature for all purposes.

[SIGNATURES ON FOLLOWING PAGE]

TOR01: 5133820: v4

IN WITNESS WHEREOF, the Parties have duly executed this Agreement on the Effective Date.

THE CORPORATION OF NORFOLK COUNTY

By: ______________________________

Name: Dennis Travale
Title: Mayor

HYDRO ONE INC.

By: ______________________________

Name: Carmine Marcello
Title: President and Chief Executive Officer

BORDEN LADNER GERVAIS LLP

By: ______________________________

Name: J. Mark Rodger
Title: Partner

SCHEDULE 3.1(L) – REAL PROPERTY, LEASED PROPERTY AND EASEMENTS

PART I

Real Property

Norfolk Power Distribution Inc.

- Distribution Stations
  - NP1 Simcoe Victoria DS – 73 Victoria St., Simcoe
  - NP2 Simcoe Wellington DS – 16 Wellington St., Simcoe
  - NP3 Simcoe Chapel DS – 270 Chapel St., Simcoe
  - NP4 Simcoe Blueline DS – 998 Blueline Road, Simcoe
  - NP5 Simcoe Evergreen DS – 65 Evergreen Hill Road, Simcoe
  - NP6 Simcoe Ireland DS – 656 Ireland Road, Simcoe
  - NP8 Delhi Ann DS – 176 Ann St., Delhi
  - NP9 Delhi Industrial DS – 60 Industrial Road, Delhi
  - NP10 Waterford Blueline DS – 2276 Blueline Road, Waterford
  - NP11 Port Dover St. Andrews DS – 121 St. Andrew St., Port Dover
  - NP12 Port Dover Scott DS – 13 Scott St., Port Dover
  - NP13 Port Dover Prospect DS – 179 Prospect St., Port Dover
- Transformer Station
  - Bloomsburg TS – 27 Old Hwy 24, Waterford
- General Real Estate
  - Main Office and Service Centre – 70 Victoria St., Simcoe;
  - Pond Street Storage Building – Corner Pond and Victoria St. Simcoe;
  - Port Rowan Rental Property – 1120 Bay St., Port Rowan (Part of Lot 1, Block 35, Plan 168);*
  - NP7 Simcoe Oakwood DS – 16A Oakwood Drive, Simcoe.
- Real Property to be Sold Prior to Closing
  - 32 Nichol Street, Waterford (Closing on March 28, 2013)

Leased Property

Norfolk Power Distribution

- Plan 182, Block 30, Lot 1 to Lot 7, Block 40, Part Lot 2 in Norfolk County in the Province of Ontario

Easements/Right of Ways

Norfolk Power Inc.

- Windham Street – Norfolk County transfer of easement to Norfolk Power

Norfolk Energy Inc.

- Canadian National Railway Company – Right of Way along Cayuga Subdivision located between mile 80.92 and 82.46;
- Southern Ontario Railway – 241 Stuart Street West P.O. Box 953 Hamilton, ON L8N 3P9.

Norfolk Power Distribution Inc.

- [redacted]
- Dover Coast - Port Dover
- Elmhurst Avenue Condos - 310 West Street, Simcoe
- [redacted]
- Hydro One – Transfer of easements to NPDI
- Industrial Drive/ Windham Street Closed Road – Simcoe
- [redacted]
- 800 Main Street, Port Dover
- [redacted]
- New Lakeshore Road – Port Dover
- 1358609 Ontario Limited – 29 Freeman Cres., Simcoe
- Orchard Park Phase IV – Simcoe
- [redacted]
- Villages of Long Point Bay
- Village Park – Harvest Lane, Delhi
- [redacted]
- St. Peter's Evangelical Lutheran Church – 155 Colborne St., Simcoe
- Norfolk County – 16A Oakwood Ave., Simcoe (right-of-way)

Other

- 614519 Ontario Limited - Pt L 3, C 14, Simcoe (held by Simcoe Hydro-Electric Commission)
- [redacted]
- Brook Conservation Lands (held by Simcoe Hydro-Electric Commission)
- Crosier Street – Delhi (held by Delhi Hydro-Electric Commission)
- [redacted]
- Ireland Road – L4 C3, 4 Woodhouse (held by Simcoe Hydro-Electric Commission)
- Lynndale Heights Public School – Donly Drive S., Simcoe (held by Simcoe Hydro-Electric Commission)
- [redacted]
- Proctor Marine – 495 Queesway W., Simcoe (held by Simcoe Hydro-Electric Commission)
- [redacted]
- [redacted]
- South Oakes Holdings Ltd, - Stephens Court, Simcoe (held by Simcoe Hydro-Electric Commission)
- [redacted]
- Trademark Warehousing – Robinson St., Simcoe (held by Simcoe Hydro-Electric Commission)
- Alley closure – Waverly & Brock Streets, Delhi (held by Delhi Hydro-Electric Commission)

*Previously 1120 Main Street, Port Rowan.

<u>PART II</u>

<u>(A)</u>

1. 65 Evergreen Hill Road, Simcoe – granted to Bell Canada.
2. 70 Victoria Street, Simcoe – granted to Norfolk County – Right-of-way to permit persons, animals and vehicles.

<u>(B)</u>

3. 60 Industrial Road, Delhi – Oil & Gas lease
4. 998 Blueline Road, Simcoe – Oil & Gas lease

SCHEDULE 3.1(M) – INTELLECTUAL PROPERTY

- Norfolk Power Inc., Norfolk Power Distribution Inc. and Norfolk Energy Inc. logos and related designs.

SCHEDULE 3.1(N) - CONTRACTS AND COMMITMENTS

[redacted]

Left intentionally blank for MAAD Application

[redacted]

Left intentionally blank for MAAD Application

[redacted]

Left intentionally blank for MAAD Application

[redacted]

Norfolk Energy Inc.

Left intentionally blank for MAAD Application

[redacted]

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[redacted]

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SCHEDULE 3.1(O) – MATERIAL CONTRACTS

[redacted]

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SCHEDULE 3.1(P) – EMPLOYEE PLANS

Norfolk Power Inc. and Norfolk Power Distribution Inc. (as applicable)

1. Life insurance offered under Equitable Life Policy Number 98476
2. Life insurance offered under MEARIE Group Policy Number 331268
3. Dependent life insurance offered under MEARIE Group Policy Number 331268
4. Optional life insurance offered under MEARIE Group Policy Number 331268
5. Accidental death and dismemberment offered under ACE INA Life Insurance Policy Number CA 10368519
6. Critical care offered under ACE INA Life Insurance Policy Number CA 10368519
7. Long-term disability offered under Equitable Life Policy Number 98476
8. Weekly indemnity offered under Equitable Life Policy Number 98476
9. Health care offered under Equitable Life Policy Number 98476
10. Vision care offered under Equitable Life Policy Number 98476
11. Vision care offered by Norfolk Power (self-insured and administered by Norfolk Power)
12. Paramedical services offered under Equitable Life Policy Number 98476
13. Dental care offered under Equitable Life Policy Number 98476
14. Orthodontic care offered by Norfolk Power (self-insured and administered by Norfolk Power)
15. Smoking cessation offered by Norfolk Power (self-insured and administered by Norfolk Power)
16. Wellness benefit offered by Norfolk (self-insured and administered by Norfolk Power)
17. Employee Assistance Plan offered under Ceridian Policy Number 102893
18. The OMERS Pension Plan

19. Group registered retirement savings plan offered under Manulife Group Insurance Contract Number 20001873

20. Overtime entitlement for management Employees (self-insured and administered by Norfolk Power).

21. Personal use of vehicle (self-insured and administered by Norfolk Power).

22. Tuition assistance offered by Norfolk Power (self-insured and administered by Norfolk Power).*

23. The contracts referred to in Section 3.1(n).

- **<u>Exceptions Referred to in Section 3.1(p)(iv):</u>**

1. The contracts referred to in Section 3.1(n)

- **<u>Exceptions Referred to in Section 3.1(p)(v):</u>**

1. Group registered retirement savings plan offered under Manulife Group Insurance Contract Number 20001873

2. Life insurance offered under MEARIE Group Policy Number 331268

3. Health care offered under Equitable Life Policy Number 98476

4. Vision care offered under Equitable Life Policy Number 98476

5. Vision care offered by Norfolk (self-insured and administered by Norfolk)

6. Paramedical services offered under Equitable Life Policy Number 98476

7. Dental care offered under Equitable Life Policy Number 98476

8. The contracts referred to in Section 3.1(n)

* Norfolk Power is prepared to pay 100% of the tuition costs provided the employee successfully completes the course and their supervisor pre-approves the course

SCHEDULE 3.1(Q) – COLLECTIVE AGREEMENT

Norfolk Power Distribution Inc.

1. Collective Agreement between Norfolk Power Distribution Inc. and Power Workers' Union of Public Employees, Local 1000 – C.L.C. dated March 8, 2011 (as amended)

Amendments

1. Mid-Term Agreement Number NO-05, GIS Projects and Records Analyst, dated November 16, 2012

2. Mid-Term Agreement Number NO-04, Senior System Control Operator, dated November 16, 2012

3. Norfolk Power Wages – 2011 – 2013 – Pay Equity revisions

SCHEDULE 3.1(R) – EMPLOYEES

[redacted]

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SCHEDULE 3.1(S) – INSURANCE POLICIES

1. MEARIE Comprehensive Liability Insurance Program (#L2013NORP1)
2. MEARIE Property Insurance Program (#P2013NORP1)
3. MEARIE Fleet Vehicle Insurance Program (#V2013NORP1)

SCHEDULE 3.1(T) – ENVIRONMENTAL DISCLOSURE

[redacted]

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SCHEDULE 3.1(U) – VENDOR LITIGATION

1. Nil.

SCHEDULE 3.1(V) - TAXES

1. Statement of Audit Adjustments for NPDI dated February 28th, 2013 from Canada Revenue Agency re: Account/Business Number [redacted], GST/HST Audit for the Period 2009-01-01 to 2012-06-30;

2. Letter dated December 6th, 2012 from Canada Revenue Agency re: NEI, Account/ Business Number [redacted], Audit Period: 2008-11-01 to 2011-12-31; and

3. Statement of Audit Adjustments for NEI dated March 14, 2013 from Canada Revenue Agency re: Account/Business Number [redacted], Audit Period: 2008-11-01 to 2011-12-31.

SCHEDULE 3.1(X) – PERMITTED ENCUMBRANCES

[redacted]

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SCHEDULE 3.1(Z) – LICENCES

Norfolk Power Distribution Inc.

- Ontario Energy Board Electricity distributor licence ED-2002-0521, issued October 22, 2003.

Norfolk Energy Inc.

- CRTC License, Entity ID 748329, granted on February 2, 2012.

SCHEDULE 3.1(AA) – BANK ACCOUNTS

[redacted]

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SCHEDULE 5.2 – PERMITTED DISPOSITIONS

1. [redacted]
2. Payment of dividend from any of the Norfolk Corporations.

SCHEDULE 6.1 – COMMUNITY INVOLVEMENT

The Purchaser shall offer the following Community Citizenship Plan in Norfolk County:

- PowerPlay (up to $25,000 per facility);
- Employee Volunteer Grant ($1000 per employee with 50 or more hours of volunteer time);
- Annual Charity Campaign (2012 campaign raised over $1,000,000 in employee donations directed to charity of employee's choice); and
- Support for local events.

SCHEDULE 6.6 – CAPEX

	2013	2014	2015	2016	2017
CapEx (M$)	3.4	3.2	3.2	3.3	3.4

SCHEDULE 6.7 – RATE HARMONIZATION FOR NPDI

Rate Class	Dx Charges	2013 Current Rates	2014 Reduced Rates	2015 Reduced Rates	2016 Reduced Rates	2017 Reduced Rates	2018 Reduced Rates
Residential	SrChg [$/month]	20.77	20.56	20.56	20.56	20.56	20.56
	VarChg [c/kWh]	2.17	2.15	2.15	2.15	2.15	2.15
	LV Chg [$/kWh]	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009
GS < 50 kW	SrChg [$/month]	49.74	49.24	49.24	49.24	49.24	49.24
	VarChg [c/kWh]	1.55	1.53	1.53	1.53	1.53	1.53
	LV Chg [$/kWh]	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008
GS > 50 kW	SrChg [$/month]	244.38	241.94	241.94	241.94	241.94	241.94
	VarChg [$/kW]	3.9413	3.9019	3.9019	3.9019	3.9019	3.9019
	LV Chg [$/kW]	0.305	0.302	0.302	0.302	0.302	0.302

HYDRO ONE INC.
ANNUAL CONSOLIDATED FINANCIAL STATEMENTS

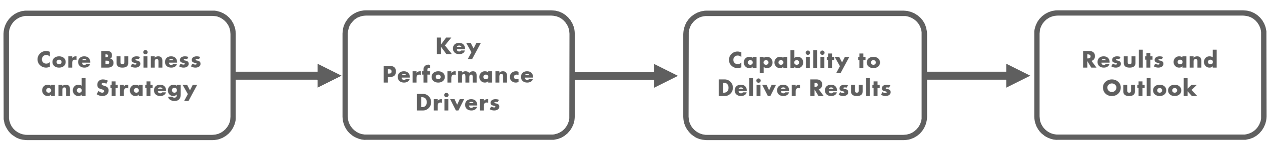
On January 1, 2012, Hydro One Inc. (Hydro One) adopted United States (US) Generally Accepted Accounting Principles (GAAP) as its approved basis for accounting and financial reporting. Comparative 2011 information is presented under US GAAP, unless otherwise noted. All amounts are in Canadian dollars.

The following discussion is based on our Consolidated Financial Statements for the years ended December 31, 2012 and 2011.

EXECUTIVE SUMMARY

We are wholly owned by the Province of Ontario (Province), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). Our mission and vision has 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 strive to 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; excellence; stewardship; 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, transparent and which 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 2012, we continued to focus on our core businesses and our commitment to our customers and made important contributions to the rebuilding of Ontario's core infrastructure while continuing to meet the requirements of the Green Energy Act (GEA).

We manage our business using the following framework:



Core Business and Strategy

Our corporate strategy is based on our mission and vision and our values. Our strategic goals, which are discussed in the section "Our Strategy," 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

Performance drivers have been identified that relate to achieving certain of our company's strategic goals. We establish specific performance targets for each driver aimed at measuring the achievement of our strategic goals over time. For example, we track the duration of unplanned customer interruptions per delivery point as an indication of our commitment to provide a reliable transmission system for our customers. We measure transmission and distribution unit costs as an indication of our commitment to increasing productivity. These and other key performance drivers are included in our discussion of our performance measures in the section "Performance Measures and Targets."

Capability to Deliver Results

We continue to use a balanced scorecard approach as we strive to manage our performance and deliver results each and every year. In 2012, we set nine stretch targets and we met or exceeded five of them. In 2011, we met or exceeded 13 of 17 stretch targets. We exceeded our target for minimizing the duration of unplanned customer interruptions within our Transmission Business. Our performance with respect to productivity was on target in our subsidiary Hydro One Networks Inc.'s (Hydro One Networks) transmission and distribution businesses. Our ability to deliver results in each of our strategic areas is limited by risks inherent in our regulatory environment, our business, our workforce and in the economic environment. These risks, as well as our strategies to mitigate them, are discussed in the section "Risk Management and Risk Factors."

Results and Outlook

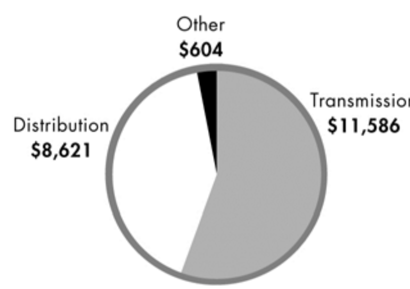
During 2012, our financial fundamentals remained strong with current year net income of $745 million. Our OEB-approved revenue requirement for our transmission business for 2012 was $1,418 million. Our 2011 distribution rates for Hydro One Networks continued unchanged throughout 2012, and its approved revenue requirement for 2011 was $1,218 million. Approved rates support the work programs required to sustain our critical infrastructure and invest in a sustainable electricity system that supports renewable and cleaner generation. We successfully issued $1,085 million in debt financing in 2012, the proceeds of which were used to fund the retirement of $600 million of debt maturing in the year and to fund a portion of our capital expenditures and other corporate requirements. A full discussion of our results of operations and financing activities can be found in the sections "Results of Operations" and "Liquidity and Capital Resources."

In 2012, we invested more than $1.4 billion in capital expenditures to improve system reliability and performance, address our aging power system, facilitate new generation and improve service to our customers. Capital expenditures for the next few years will include those required to build critical infrastructure identified in the Long-Term Energy Plan (LTEP), which is based on recommendations from the Ontario Power Authority (OPA), and expenditures to address aging infrastructure. Our future capital expenditures are more fully described in the section "Future Capital Expenditures."

OVERVIEW

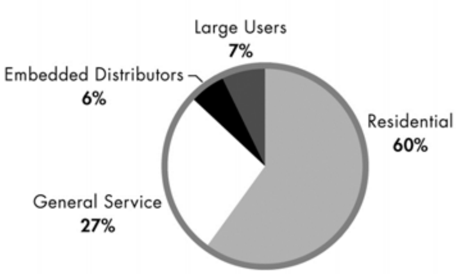
Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our subsidiary Hydro One Networks. 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 2012, we earned total transmission revenues of $1,482 million, primarily by transmitting approximately 141 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 it is linked to five adjoining jurisdictions through 26 interconnections, through which we can accommodate imports of about 4,800 MW and exports of approximately 6,000 MW of electricity. In terms of assets, our Transmission Business is our largest business segment, representing approximately 56% of our total assets at December 31, 2012.



Total Assets
December 31, 2012
(CAD $ millions)

Distribution



2012 Distribution Revenues

Our consolidated distribution system is the largest in Ontario and it spans roughly 75% of the province. We serve approximately 1.4 million rural and urban customers and 440 large user customers. Our subsidiary Hydro One Remote Communities Inc. (Hydro One Remote Communities) operates small, regulated generation and distribution systems in a number of remote communities across northern Ontario that are not connected to Ontario's electricity grid. In 2012, we earned total distribution revenues of $4,184 million. As illustrated in the accompanying chart, over half of our distribution revenues were earned from our residential customers. At December 31, 2012, our Distribution Business assets represented approximately 41% of our total assets.

Other

In 2012, our Other business segment contributed revenues of $62 million, and had assets of $604 million at December 31, 2012, representing 3% of our total assets. This segment primarily represents the operations of our wholly-owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements, 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, those who work on our property, and the public.

Excellence: We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality and cost-effective service, with integrity.

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 are inextricably linked. 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 implement the internationally recognized health and safety management system, ISO 18001, to identify health and safety risks, priorities and mitigation in order to further drive our safety culture. 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. We will develop and deliver targeted customer segment strategies, products and delivery channels that will respond to their unique needs and behaviours.

Continuous innovation. Innovation represents one of our core values and is critical to achieving our mission and vision. 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. The Advanced Distribution System (ADS) is a key element in our investment in innovation and will improve operation of our distribution assets and deliver further value to our customers.

Building and maintaining reliable, cost-effective transmission and distribution 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 ADS technology to provide greater visibility; increasing control and improving customer service; supporting the connection of renewable energy sources; seeking efficiencies through leveraging technology and operational experience from our transmission system; providing reliable and cost-effective service over a diverse geography; and pursuing commercial arrangements that are anticipated to arise from the rationalization of Ontario's distribution sector.

Protecting and sustaining the environment for future generations. Consistent with our value of stewardship, we play 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. We will engage our customers further regarding how we manage our sustainability obligations and activities on their behalf.

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 corporate culture, labour demographics, diversity, development of critical core competencies and skill and knowledge retention. Our labour strategy should enable us to make significant gains in the areas of labour flexibility, productivity improvement and cost reduction.

Maintaining 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. We will explore and pursue opportunities to increase the revenue-earning potential of our company by leveraging existing assets, technologies, capabilities and the geographic presence of our company.

Achieving productivity improvements 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 Ontario's economy and its residents.

Performance Measures and Targets

We target and measure our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we maintain a focus on our strategic objectives and take mitigating actions as required. In 2012, we met or exceeded five of nine stretch targets. Overall, we are making progress towards achieving many of our strategic goals.

Achieving productivity improvements and cost-effectiveness

One of our strategic objectives is to increase productivity through efficiency improvements and effective management of costs. The measures for this objective for 2012 were transmission unit cost and distribution unit cost.

For 2012, we measured for transmission unit cost the capital expenditures and operation, maintenance and administration costs per dollar of gross in-service assets (expressed as a percentage). For distribution unit cost, the measure is capital expenditures and operation, maintenance and administration costs per kilometre of line ($'000/km) due to the length of line required to connect our rural customers. Our objective with our ongoing work and investment program is to maintain and improve our assets and monitor our productivity year-over-year. Our transmission unit cost target was set at 10.1% and we met this target. The distribution unit cost target was set at $11,000 per kilometre of line and we also met this target.

Building and maintaining reliable, cost-effective transmission and distribution systems

We continue to build and retain public confidence and trust in our operations, as stewards of Ontario's electricity grid. In 2012, 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 customers in a safe, reliable and efficient fashion. We are conscious that commercial customers of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration when interruptions occur. Transmission and distribution reliability is measured through the duration of customer interruptions.

For the duration of unplanned customer interruptions within our Transmission Business, the target for 2012 was 10 minutes per delivery point. We more than met this target.

For the Hydro One Networks distribution business, the target for 2012 for the duration of customer interruptions was set at 6.7 hours per customer. We did not meet this target.

Satisfying our customers

Customer satisfaction measures the degree to which our transmission and distribution customers are satisfied with the service they receive from our company. Customer satisfaction is based on the results of customer surveys conducted on our behalf by independent third parties. In 2012, for transmission customers we targeted a customer satisfaction rate of 90%, but did not meet this target. For our distribution customers, we targeted a satisfaction rate of 86%, and we met this target.

Employee engagement

We continue to focus efforts on increasing employee engagement throughout the company. An engaged workforce is one in which employees embrace the corporate values of safety, stewardship, excellence and innovation. The process of measuring and improving such engagement began in 2008 by means of an employee engagement survey administered by an independent third-party expert. Our goal is to improve the grand mean score year-over-year. The target of improving the grand mean score to 4.06 (out of 5) in 2012 was not met.

Maintaining a commercial culture that increases value for our shareholder

Achievement of strong financial performance is measured by a performance measure of targeted level of net income after tax. Our target was $643 million net income after tax and we exceeded our target.

Creating an injury-free workplace and maintaining public safety

The safety of our employees is paramount. In 2012, we used medical attentions, defined as injuries that require treatment by a medical practitioner (beyond first aid), as the performance measure for this strategic objective. The medical attentions measure reflects incidents that are reported to the Workplace Safety and Insurance Board and is calculated as the number of attentions per 200,000 hours worked. In 2012, Hydro One set a target of no higher than 2.2 attentions per 200,000 hours worked. In an effort to achieve this target, we engaged in a number of activities, such as: continued emphasis on improving health and safety through face-to-face sessions; continuation of our Journey to Zero initiative; better monitoring of mandatory skills and safety training; an enhanced driver training/evaluation program; and field coaching to increase the expectations from supervisors and staff. The number of attentions in 2012 improved by 35% compared to the number in 2011 but was still slightly higher than our target for 2012.

REGULATION

Our electricity transmission and distribution businesses are licenced 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 province-wide uniform transmission rates (UTRs) 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 a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory accounts over specified timeframes.

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 both a two-tiered electricity pricing structure, with seasonal consumption thresholds, and a three-tiered electricity pricing structure with Time of Use (TOU) thresholds. The majority of our RPP customers are now on TOU billing. Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the OPA. Prices are reviewed by the OEB 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.

We started migrating our customers to TOU rates in 2010 and the majority of our customers were transitioned to TOU rates by the end of 2011. We received an exemption from the OEB, effective until December 31, 2014, from implementing mandatory TOU pricing for approximately 120,000 customers that are currently out of reach of our smart meter telecommunications infrastructure.

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 by the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998*. The IESO is responsible for overseeing and operating the wholesale market as well as ensuring the reliability of the integrated power system.

Transmission Rates

The IESO facilitates payments to us based on the Ontario UTRs approved by the OEB for all transmitters across Ontario.

On May 19, 2010, we submitted our application for 2011 and 2012 transmission rates in continued support of our aging critical infrastructure and 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 represented estimated rate increases of 15.7% and 9.8%, respectively, or 1.2% and 0.7% on an average customer's monthly bill.

On December 23, 2010, the OEB issued its decision, which resulted in a revenue requirement effective January 1, 2011 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, or 0.5% and 2%, respectively, on an average customer's total bill. Our 2012 revenue requirement was impacted by the OEB directing us to adopt a cost capitalization policy consistent with International Financial Reporting Standards (IFRS). This specific accounting revision resulted in an increased revenue requirement of about $200 million for 2012.

Consistent with an approval from the Ontario Securities Commission (OSC) to adopt US GAAP for our external financial reporting and securities filings, on July 15, 2011 we filed a Motion to Vary the OEB's 2012 rate decision. Our application sought approval to adopt US GAAP as a basis for regulatory accounting and rate setting in place of the OEB's approved modified IFRS basis. On November 23, 2011, the OEB approved the use of US GAAP by our Transmission Business, which resulted in the reversal of the $200 million adjustment that was made by the OEB in its December 2010 rate decision.

On December 1, 2011, we submitted to the OEB a draft 2012 transmission revenue requirement that reflects the approved adoption of US GAAP for rate-setting purposes as well as the OEB-directed update to 2012 cost-of-capital parameters. On December 20, 2011, the proposed $1,418 million 2012 revenue requirement was approved by the OEB along with new 2012 UTRs effective January 1, 2012. The new rates resulted in an approximate 8% transmission rate increase, or 0.6% on an average customer's total bill. The adoption of US GAAP in lieu of modified IFRS as a basis for rate setting decreased the approved rates by about 15%.

To achieve the necessary funding in support of aging critical infrastructure and investments, we submitted a cost-of-service rate application to the OEB for our 2013 and 2014 transmission rates on May 28, 2012. The application sought OEB approval for revenue requirement increases of approximately 0.6% and 9.1% in 2013 and 2014, respectively, or estimated increases of 0% in 2013 and 0.7% in 2014, on an average customer's total bill. A settlement conference was held in October 2012, where Hydro One Networks and the intervenors reached an agreement, settling all issues apart from Export Transmission Service. This is anticipated to be settled in early 2013 but is not expected to affect our company's results of operations. The settlement agreement was reviewed and approved by the OEB on November 8, 2012. On November 30, 2012, we submitted a draft rate order, which includes revenue requirements of approximately $1,438 million and $1,528 million for 2013 and 2014, respectively. For the transmission portion of the bill, this represents no change from existing 2012 OEB-approved rate levels in 2013 and a 5.8% increase in 2014. On an average customer total bill basis, this represents increases of nil for 2013 and 0.5% for 2014. On December 20, 2012, the OEB issued a final Rate Order, approving Hydro One Networks' 2013 transmission revenue requirement for use in setting the 2013 Ontario UTRs.

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 itself.

In 2006, the OEB established a multi-year electricity distribution rate-setting plan whereby a distributor's rates are set via a cost-of-service rebasing application followed by an Incentive Regulation Mechanism (IRM) that uses a formulaic approach to establish rates for the next three years. In 2012, the OEB issued a new regulatory framework that included three rate-setting methods available to distributors (see "Renewed Regulatory Framework").

Hydro One Networks

On July 13, 2009, our subsidiary Hydro One Networks filed a cost-of-service application with the OEB for 2010 and 2011 distribution rates.

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.

On November 15, 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. The lowering of the return on equity (ROE) produced a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement resulted in an average distribution rate increase of approximately 8.7% for 2011, or 3.4% on an average (i.e. consuming 800 kWh per month) customer's total bill.

On March 23, 2012, the OEB approved our request for Hydro One Networks' distribution business to adopt US GAAP for rate setting and regulatory accounting and reporting. Hydro One Networks did not seek a distribution cost-of-service rate adjustment for 2012 and rates continued unchanged at 2011 levels.

On June 15, 2012, Hydro One Networks filed evidence in support of its application for 2013 distribution rates on the basis of the OEB's 3rd Generation IRM process. Hydro One Networks and intervenors subsequently reached a settlement and submitted a settlement agreement to the OEB. On December 14, 2012, the OEB issued its decision accepting the agreement as filed. On December 20, 2012, the OEB issued a final Rate Order. The distribution rate of an average residential customer will increase by approximately 1.3% in 2013, or by 0.4% when considering total bill impacts. In addition, the Retail Transmission Service Rates adjustment, which was accepted in the Settlement, will bring the total bill increase in 2013 to approximately 1.5%.

Hydro One Brampton Networks

On June 30, 2010, our subsidiary Hydro One Brampton Networks submitted its 2011 cost-of-service application, which was subsequently adjusted in September to reflect the optional deferral of the adoption of modified IFRS until January 1, 2012, consistent with a decision by the Canadian Accounting Standards Board (AcSB). The AcSB later extended the optional deferral to January 1, 2014 and Hydro One Brampton Networks has decided to exercise this option.

Following another adjustment to the application in November 2010, the revenue requirement was approximately $63 million. On April 4, 2011, the OEB issued a decision that approved a revenue requirement of $59.5 million for 2011. The revised rates were approved with an effective date of January 1, 2011 and an implementation date of May 1, 2011. Included in the rates is an amount of $1.52 per month per metered customer for smart meters and approval of a GEA funding adder of $0.02 per month per metered customer. The new rates result in a total bill increase for an average customer (i.e. consuming 800 kWh per month) of approximately 0.5%.

On September 15, 2011, Hydro One Brampton Networks filed an application for 2012 rates on the basis of the OEB's 3rd Generation IRM process. On December 22, 2011, the OEB issued its decision and on December 31, 2011, the OEB declared Hydro One Brampton Networks' existing rates interim as of January 1, 2011. On January 5, 2012, the OEB released a decision that resulted in a reduction in rates of approximately 13.2%, or a 1.7% reduction on the average customer's total bill in the year. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates.

On August 3, 2012, Hydro One Brampton Networks filed an application for 2013 rates on the basis of the OEB's 3rd Generation IRM process, requesting new distribution rates effective January 1, 2013. Hydro One Brampton Networks subsequently amended its rate application and on December 6, 2012, the OEB approved the amended application. The rate impact on the distribution component associated with a typical residential customer was an increase of approximately 0.3%, or less than 0.1% on the customer's total bill.

Hydro One Remote Communities

On October 15, 2010, Hydro One Remote Communities filed an application for 2011 distribution rates on the basis of the OEB's 3rd Generation IRM. The application sought approval for an increase of approximately 0.4% to basic rates for the distribution and generation of electricity effective May 1, 2011. On March 28, 2011, the OEB approved the application. The overall impact of the new rates on an average (i.e. consuming 800 kWh per month) residential customer's total bill was marginal.

On November 25, 2011, Hydro One Remote Communities filed its application for 2012 distribution rates on the basis of the OEB's 3rd Generation IRM. On March 22, 2012, the OEB issued its decision approving a rate increase of 1.08% effective May 1, 2012, representing an increase of about $1 on an average residential customer's monthly bill.

Consistent with the OEB's decision affirming the use of US GAAP for rate-setting purposes by Hydro One Networks' transmission and distribution businesses, we made a similar request to use US GAAP for Hydro One Remote Communities. On April 3, 2012, the OEB approved the request to use US GAAP as the basis for rate setting within Hydro One Remote Communities effective January 1, 2012.

On September 17, 2012, Hydro One Remote Communities filed a cost-of-service application for 2013 rates to be effective May 1, 2013. If approved as filed, the electricity rate of an average customer will increase by 3.5% in 2013. In its rate application, Hydro One Remote Communities also requested approval to establish a Rural and Remote Rate Protection of $35 million in 2013. The OEB Hearing and decision are anticipated to occur in the first quarter of 2013.

Recent Industry Developments

Long-Term Energy Plan

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. On February 17, 2011, the Province issued a Supply Mix Directive that required the OPA to prepare a 20-year Integrated Power System Plan (IPSP) to meet the goals set out in the LTEP. On May 9, 2011, the OPA announced that it was beginning consultations to update Ontario's IPSP and issued the *IPSP Planning and Consultation Overview* document. On June 17, 2011, we submitted our comments on the IPSP, as requested of stakeholders by the OPA. Stakeholder comments will form part of the evidence when the OPA submits the revised IPSP to the OEB for its review.

On February 28, 2011, the OEB issued a decision amending Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy to the OEB. The licencee amendment requires Hydro One Networks to develop and either seek approvals for, or implement, specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy in accordance with recommendations from the OPA. In a letter dated April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at ten of 15 transformer stations noted in the licence to accommodate small-scale renewable generation. Six of these upgrades have been completed and we are currently anticipating that one additional station upgrade will be placed in service in 2013. Alternative solutions have been identified for the other three upgrades. In accordance with the Memorandum of Agreement between Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (Shareholder) and our company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. As a result, the recovery of the seven station upgrades was restricted. We charged $17 million to operation, maintenance and administration expense in 2012 and charged $19 million to operation, maintenance and administration expense in 2011, in respect of these projects.

In June 2011, the OPA recommended the scope and timing of the project to re-conductor two circuits between Sarnia and London, our West of London Transmission Upgrade Project, with a required in-service date of December 2014. This project is needed to satisfy government policy relating to the incorporation of 10,700 MW of non-hydroelectric renewable generation resources by 2018. On November 8, 2012, the OEB issued a decision approving our Section 92, Leave to Construct, application for this project. In October 2011, the OPA recommended the scope and timing of the Southwestern Ontario Reactive Compensation Priority Project, recommending that we install a Static Var Compensator (SVC) at our Milton Switching Station to increase the capability of our Bruce to Milton Line. An OPA recommendation regarding the construction of a new transmission line west of the City of London is not expected in the foreseeable future.

Framework for Transmission Development Plans

On August 26, 2010, the OEB released its new policy entitled *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 process. On March 29, 2011, the Minister of Energy expressed the Province's interest in the OEB commencing a transmitter designation process for the East-West Tie Line. The East-West Tie Project is the first transmission network line expansion covered under the new competitive approach. The proposed route is a 400 km, 230 kV double-circuit line between its transformer stations at Wawa in the east and Lakehead in the west. The target in-service date, set by the OPA in its report issued June 30, 2011, is 2017. The East-West Tie LP, an equally-shared partnership of three entities including our company, obtained a transmission licence on May 31, 2012, and is participating in the East-West Tie Project bid process.

The OEB adopted a two-phase process for the East-West Tie proceeding. On July 12, 2012, the OEB issued its Phase 1 decision and order, thus concluding Phase 1 of the proceeding by finalizing various filing requirements and process issues and directing registered transmitters to file their applications for designation by January 4, 2013. The proceeding is now in Phase 2 and the OEB received six applications for designation from the registered transmitters in the proceeding, including one from the East-West Tie LP. The timeline for Phase 2, which will take the form of a written hearing, has not yet been set.

Renewed Regulatory Framework

On December 17, 2010, the OEB initiated a coordinated consultation process for the development of a renewed regulatory framework for electricity distributors and transmitters. On October 18, 2012, the OEB issued its report *A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, marking the completion of its consultation process. The report identified three rate-setting models available to provide choices suitable for distributors having varying capital requirements: a 4th Generation IRM, which builds on the current 3rd Generation model by adding one year to the IRM period; a Custom IRM, which involves rate setting based on a five-year forecast of a distributor's revenue requirement and sales volume; and an Annual Incentive Rate-setting Index method, which involves annual adjustment of rates by a simple price cap index formula. The report also provided information on performance measurement, continuous improvement and implementation of the new framework.

Four working groups were established to provide expert assistance to review and advise the OEB's staff on proposals regarding certain implementation matters: Asset Redefinition and Regional Infrastructure Planning Process; Distribution Network Investment Planning; Performance, Benchmarking, and Rate Adjustment Indices; and Smart Grid. Hydro One Networks is represented on all four groups. Working group meetings began in November 2012 and are scheduled through February 2013. Consultations will conclude with the issuance of filing requirements and guidance, code amendments, and/or supplemental Board policies in support of the new framework. The OEB is expecting that policies will be largely implemented in time for the 2014 rate year. We are currently assessing the rate-setting methods available.

OEB Transmission and Distribution System Codes

Under the Transmission System Code, the transmitter covers the initial pooling of the costs of enabler lines, with generators paying their pro-rata share when ready to connect, based on generator capacity.

Under the Distribution System Code (DSC), there are three classes of distribution assets associated with the connection of renewable energy generation: connection assets, expansion assets, and renewable enabling improvements. Generators that connect directly to a distributor's system pay the costs of connection assets, while distributors fund: all expansion costs identified in a plan; other generator-requested expansion costs up to a cap of $90,000/MW per project (generator pays the rest); and all renewable enabling improvements.

In 2011, the OEB granted us an exemption from mandatory DSC timelines for the connection of micro-embedded generation facilities. The OEB decision increased the timeline for processing indirect connections that require a site assessment and approved amendments to the conditions that must be met before we are required to connect micro-embedded generation facilities to our distribution system. On August 3, 2012, Hydro One Networks applied to the OEB for an extension of the exemption and on November 8, 2012, the OEB granted the extension for a period ending August 3, 2013, or six months after the conclusion of its consultation on micro-embedded generation issues, whichever is earlier.

Ontario Clean Energy Benefit

Effective January 1, 2011, 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 a 10% benefit with respect to the total cost of electricity on their bills, including tax, for a five-year period. This benefit is applied to customers' electricity costs for each billing period. Effective September 1, 2012, the 10% rebate is applied only to the first 3,000 kWh of electricity consumed per month.

Revenue Decoupling for Distributors

In 2010, the OEB initiated a consultation process to examine the revenue adjustment and cost recovery mechanisms available to electricity and natural gas distributors to address revenue erosion resulting from unforecasted changes in volume of energy sold. These mechanisms are commonly referred to as "revenue decoupling" mechanisms as each involves some means of disconnecting the link between the volume of energy consumed by customers and the recovery by energy distributors of their approved revenue requirement.

On November 26, 2012, the OEB initiated a project to complete the work begun on revenue decoupling for electricity and natural gas distributors. The OEB will coordinate its consideration of revenue decoupling with the new rate-setting policies proposed in the renewed regulatory framework for electricity. The OEB will examine how best to address changes in demand, including potential declines in average use. This consultation will review the options for potential revenue decoupling in addition to the existing lost revenue decoupling mechanism (i.e. the Lost Revenue Adjustment Mechanism or LRAM). The OEB expects to release a draft policy in early 2013. The OEB will solicit stakeholder comments in writing before finalizing the policy.

Distribution Sector Consolidation

On April 13, 2012, the Province announced it was launching a comprehensive review of Ontario's electricity sector to explore options to improve efficiencies, including local distribution companies (LDCs) consolidation. As a result, the Province created the Ontario Distribution Sector Review Panel (Panel). On December 13, 2012, the Panel released its report, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First*, with recommendations for electricity sector consolidation. This report recommends that the 73 LDCs comprising the focus of the report be consolidated into eight to 12 larger regional electricity distributors within a two-year timeframe. Specifically, it recommends there be two regional distributors in northern Ontario and between six and ten regional distributors in southern Ontario with a minimum of 400,000 customers each. Given our company's position as the largest LDC, the report recommends that Hydro One Networks be given unambiguous direction to lead and engage in the discussion of the merger of distribution assets with the appropriate interested utilities on a commercial basis. At present, the Province is reviewing the report and assessing the recommendations.

FIT and microFIT

On October 1, 2009, the OPA launched its Feed-in Tariff (FIT) Program which 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 March 22, 2012, the Province announced the results of its two-year FIT Program Review, including recommended changes to reflect input received from stakeholders. The OPA implemented these recommendations and re-launched its microFIT program on July 12, 2012. The revised program encourages greater community and aboriginal participation and the protection of agricultural lands. In August 2012, the OPA began to release approvals allowing microFIT projects to proceed. On December 14, 2012, the OPA announced that it will award up to 200 MW of Small FIT applications, received between December 14, 2012 and January 18, 2013, for renewable energy projects with a proposed capacity between ten and 500 kilowatts. The OPA is not accepting Large FIT applications at this time. The timing for the Large FIT project application window will be communicated once details are finalized.

Conservation and Demand Management (CDM)

The OPA continues to be responsible for coordinating the delivery and funding of Ontario's CDM programs. Our CDM programs funded through the OPA in 2012 amounted to approximately $25 million, compared to $15 million in 2011. These programs included: the Peaksaver Program; the Low Income Home Assistance Program; Appliance Retirement and Exchange Events; and the Process and System Upgrade Incentive Program.

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 licencees. A province-wide CDM target for Ontario's LDCs was set in 2010. The two key CDM targets for LDCs over the four-year period beginning January 1, 2011 were to collectively reduce 1,330 MW of provincial summer peak demand and to provide 6,000 GWh of cumulative energy savings. The OEB issued its CDM Code for Electricity Distributors (CDM Code) on September 16, 2010 and on November 12, 2010, it issued final CDM targets to each LDC. Our company was allocated a 259 MW reduction of provincial peak demand and a 1,320 GWh reduction of electricity consumption, representing, respectively, 19.5% and 22.0% 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 April 26, 2012, the OEB issued its CDM guidelines for all electricity distributors. One key change is that savings associated with TOU pricing are eligible to be counted towards the CDM targets. Savings will be evaluated by the OPA for the entire province and then allocated to each distributor. The other key change is the establishment of the LRAM variance account, which captures the variance between the level of CDM included in a distributor's load forecast and the verifiable results of impacts of CDM activities undertaken between 2011 and 2014 for both OPA-contracted and OEB-approved CDM programs.

On September 28, 2012 and September 30, 2012, in accordance with the CDM Code, Hydro One Brampton Networks and Hydro One Networks, respectively, filed their 2011 Annual CDM Reports with the OEB. Our combined results for 2011 were 40 MW in peak demand savings, representing 15.6% of our target, and 99 GWh of annual energy savings. These energy savings will produce 388 GWh towards our target, representing 29.4% of our cumulative target. We anticipate meeting our 2014 cumulative demand and energy savings targets.

On December 21, 2012, the Minister of Energy issued a directive to the OPA to extend funding for its CDM programs for one additional year, to December 31, 2015. This extension aims to provide added stability, support the momentum of province-wide programs and ensure that projects with longer completion times can continue to participate in key conservation initiatives. This extension will also provide an opportunity for the OPA and LDCs to collaboratively work to strengthen the current framework and deliver innovative programs that support Ontario families and businesses. The OPA will be reaching out to distributors to further solicit insight and advice on the implementation of this extension.

Advanced Distribution System

The *Energy Conservation Responsibility Act, 2006* further broadened the objectives of CDM by providing the framework for the installation of smart meters in all homes and small businesses in Ontario. In 2007, the Province appointed the IESO as the interim smart meter entity that would oversee the collection and management of data from installed smart meters. LDCs, including our distribution businesses, are accountable for the deployment of smart meter infrastructure and related communications technology to meet minimum regulatory requirements, as well as the implementation of TOU rates.

In 2011, we carried out a number of studies on advanced distribution technologies and initiated the Smart Zone Pilot Project in the Owen Sound area. The Smart Zone Pilot consists of testing and demonstrating power system equipment, IT systems and communication systems that will be required to help facilitate the connection of a large number of Distributed Generation (DG) connections to our distribution system. In 2012, we successfully completed the deployment of the Distribution Management System (DMS) within the Owen Sound pilot area. This integrates the Network Management System, the Outage Response Management System and field devices. Further releases of the ADS will look at optimizing outage response through more effective dispatch, automation to isolate faults where needed and the dynamic regulation of voltage to reduce losses. All releases leverage a core infrastructure and build on each other, and as pilot elements are proven, business cases will be developed for the provincial roll out which will ultimately comprise the ADS.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (millions of dollars)	**2012**	**2011**	**$ Change**	**% Change**
Transmission	1,482	1,389	93	7
Distribution	4,184	4,019	165	4
Other	62	63	(1)	(2)
	5,728	5,471	257	5
Average annual Ontario 60-minute peak demand *(MW)*[1]	21,132	21,166	(34)	-
Distribution – units distributed to customers *(TWh)*[1]	29.2	29.2	-	-

[1] System-related statistics are preliminary.

Transmission

Transmission revenues primarily consist of our transmission tariff, which is based on the monthly peak electricity demand 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 revenues associated with transmitting excess generation to surrounding markets and ancillary revenues which are mostly attributable to maintenance services provided primarily to generators and secondary use of our land rights.

Our transmission revenues were higher by $93 million, or 7%, compared to 2011. On December 23, 2010, the OEB rendered its decision on our 2011 and 2012 transmission rate application. On December 20, 2011, the OEB approved new transmission tariff rates, effective January 1, 2012, which reflected higher in-service assets and the use of US GAAP as our basis for rate setting. The decisions resulted in higher transmission revenues of $106 million for the year ended December 31, 2012, and the average peak demand for 2012 resulted in a slight increase of $3 million, compared to the prior year.

Increases were partially offset by a $9 million reduction in revenue following the completion of recovery of a transmission regulatory account effective December 31, 2011, a $6 million reduction in transmission-related external revenues and a $1 million reduction associated with other OEB-approved regulatory accounts.

Distribution

Our consolidated Distribution Business consists of the separate distribution businesses of our subsidiaries Hydro One Networks, Hydro One Brampton Networks, and Hydro One Remote Communities. Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our consolidated Distribution Business. Accordingly, our 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 minor ancillary distribution services revenues, such as fees related to the joint use of our distribution poles by the telecommunications and cable television industries as well as miscellaneous charges, such as those for late payments.

Our 2012 distribution revenues were higher by $165 million, or 4%, compared to 2011. The increase was primarily due to the recovery of higher purchased power costs of $146 million, as described below under "Purchased Power." Our distribution revenues were also higher by $18 million due to our placement of new ADS and smart meter investments in service. Given that these investments relate to new technologies, they are currently recovered through separate rate mechanisms.

Distribution revenues for the year reflect additional external revenues of $7 million, an increase in Hydro One Remote Communities' revenues of $2 million and a $1 million increase associated with OEB-approved regulatory accounts. These increases were partially offset by a $7 million reduction due to lower energy consumption, resulting primarily from the milder winter we experienced in 2012 compared to 2011, and by a decrease of $2 million in Hydro One Brampton Networks' distribution tariff revenues.

Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of electricity delivered to customers within our distribution service territories. These costs comprise the wholesale commodity cost of energy, the IESO's wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on TOU billing, both of which are adjusted twice annually. We began transitioning our RPP customers to TOU billing in May 2010, and a large majority of our RPP customers are now on TOU billing. Customers who 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 and comparative periods is provided below.

RPP	**Tier Threshold (kWh/month)**		**Tier Rates (cents/kWh)**	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2010	1,000	750	6.4	7.4
May 1, 2011	600	750	6.8	7.9
November 1, 2011	1,000	750	7.1	8.3
May 1, 2012	600	750	7.5	8.8
November 1, 2012	1,000	750	7.4	8.7

RPP TOU	**Rates (cents/kWh)**		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
November 1, 2010	9.9	8.1	5.1
May 1, 2011	10.7	8.9	5.9
November 1, 2011	10.8	9.2	6.2
May 1, 2012	11.7	10.0	6.5
November 1, 2012	11.8	9.9	6.3

Purchased power costs increased by $146 million, or 6%, to $2,774 million for the year, compared to 2011. The increase in our purchased power costs was primarily due to an increase of $118 million resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers, a $33 million increase resulting from the OEB transmission rate decision effective January 1, 2012 that affected the transmission charges levied by the IESO, and a $7 million increase related to higher electricity demand. The effect of these increases was partially offset by an $11 million reduction compared to 2011 in wholesale market service charges levied by the IESO, which include certain costs for operating the transmission grid, and a $1 million decrease resulting from lower purchased power costs for customers who are not eligible for the RPP.

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 related to certain of our transmission and distribution facilities.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**	**$ Change**	**% Change**
Transmission	402	422	(20)	(5)
Distribution	608	609	(1)	-
Other	61	61	-	-
	1,071	1,092	(21)	(2)

Our company continues to focus on managing its costs, resulting in a decrease in total operation, maintenance and administration expenditures in 2012, compared to 2011, while continuing to substantially complete the planned work programs for both our transmission and distribution businesses.

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $20 million, or 5%, in 2012 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 requirements were lower by $33 million compared to last year mainly due to: lower demand for station-related corrective maintenance, particularly for power equipment; lower demand for underground cable corrective maintenance; and reduced autotransformer remediation work. We also incurred lower expenditures compared to last year related to the OPA's recommendation to increase short circuit and/or transformer capacity at a number of our transmission stations to enable the connection of small renewable projects, for which recovery is restricted (see "Regulation – Long-Term Energy Plan"). Most of this work has now been completed. Expenditures in support of our transmission system increased by $13 million, compared to 2011, due to a redirection of resources from our Distribution Business, partially offset by management cost reduction initiatives.

Distribution

Operation, maintenance and administration expenditures required to maintain our low-voltage distribution system decreased slightly by $1 million compared to last year. Our work program expenditures decreased by $5 million mainly due to decreased power restoration expenditures resulting from overall lower storm activity in Ontario in 2012 compared to 2011. Reductions also resulted from lower lines maintenance requirements, partially offset by increased requirements within our forestry program resulting from higher tree densities experienced this year. Our expenditures in support of our distribution system increased by $4 million mainly due to spending in support of the Customer Information System (CIS) phase of our entity-wide information system replacement and improvement project. The impact of this increase was partially offset by cost reduction initiatives and a redirection of resources in support of our Transmission Business.

Depreciation and Amortization

Depreciation and amortization expense increased by $43 million, or 7%, in 2012, compared to 2011. This increase was attributable to higher depreciation expense of $40 million, when compared to 2011, primarily related to our placement of new assets in service consistent with our ongoing capital work program. Slightly higher asset removal costs of $3 million contributed the remainder of the variance from the prior year.

Financing Charges

Financing charges increased by $14 million, or 4%, to $358 million for 2012 compared to 2011. Higher financing costs were mainly due to an increased average level of debt and partially offset by a lower average effective interest rate.

Provision for Payments in Lieu of Corporate Income Taxes (PILs)

The provision for PILs decreased by $29 million, or 19%, to $121 million in 2012, compared to 2011. This decrease primarily resulted from a reduction in the statutory tax rate from 28.25% to 26.50%, changes in net temporary differences, and an increase in research and development tax credits related to our ADS project. This reduction was partially offset by the impact of higher levels of pre-tax income compared to 2011.

Net Income

Net income of $745 million was higher by $104 million, or 16%, than our comparable 2011 results. Higher revenues reflect the recovery of prior year investments which are now in service and which will improve the province's electricity system. Our net income was also positively impacted by lower operation, maintenance and administration expenditures resulting from cost-effectively managing the work program within our Transmission Business and by lower PILs resulting from a lower combined federal and provincial statutory income tax rate compared to 2011. In addition, our 2012 net income reflects higher depreciation expense resulting from our placement of new assets in service, consistent with our increased capital work program, and increased financing charges reflecting our higher average level of debt.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended March 31, 2011 through December 31, 2012. This information has been derived from our unaudited interim Consolidated Financial Statements and our audited annual Consolidated Financial Statements 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.

(millions of dollars)	**2012**				**2011**			
Quarter ended	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**
Total revenue	1,435	1,466	1,359	1,468	1,359	1,384	1,268	1,460
Net income	165	201	169	210	120	167	142	212
Net income to common shareholder	160	197	164	206	115	163	137	208

Electricity demand generally follows normal weather-related variations, and consequently, 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 our operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include our capital expenditures, servicing and repayment of our debt, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (millions of dollars)	**2012**	**2011**
Operating activities	1,285	1,407
Financing activities		
Long-term debt issued	1,085	700
Long-term debt retired	(600)	(500)
Dividends paid	(370)	(168)
Investing activities		
Capital expenditures	(1,454)	(1,447)
Other financing and investing activities	21	64
Net change in cash and cash equivalents	(33)	56

Operating Activities

Net cash from operating activities decreased by $122 million to $1,285 million in 2012, compared to 2011. The decrease was primarily due to changes in accrued liabilities related to customer prepayments, and a reduction in taxes payable, resulting from a tax payment made in the first quarter of 2012 related to the 2011 taxation year, as well as the timing of tax installment payments in 2012, compared to 2011. The decrease was partly offset by higher 2012 net income, compared to 2011.

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 holding of Province of Ontario Floating-Rate Notes.

Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of our $1,250 million committed revolving credit facility with a syndicate of banks, which matures in June 2017, and a long-term investment in Province of Ontario Floating-Rate Notes of $250 million (with a fair value of $251 million at December 31, 2012). 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, 2012, we had $8,460 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2013 and 2062. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million. At December 31, 2012, $1,515 million remained available until September 2013.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.[1]	Prime-1	A1
Standard & Poor's (S&P)[2]	A-1	A+

[1] On April 27, 2012, Moody's Investors Service Inc. downgraded our senior unsecured rating to A1 from Aa3.
[2] On April 25, 2012, S&P revised their outlook on our company to negative from stable.

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 third-party debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We were in compliance with all these covenants and limitations at December 31, 2012.

In 2012, we successfully issued $1,085 million in cost-effective long-term debt under our MTN Program, consisting of $300 million issued in the first quarter, $425 million issued in the second quarter, $310 million issued in the third quarter, and $50 million issued in the fourth quarter of 2012. In the third quarter of 2012, we also called and redeemed $600 million of our long-term debt, prior to its maturity date of November 15, 2012.

In 2011, we issued $700 million in long-term debt under our MTN Program, consisting of $300 million issued in the first quarter, $300 million issued in the third quarter, and $100 million issued in the fourth quarter of 2011. In 2011, we also repaid $500 million in maturing long-term debt, $250 million in the first quarter and $250 million in the fourth quarter.

We had no short-term notes outstanding as at December 31, 2012 or December 31, 2011.

Common dividends are declared at the sole discretion of our 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. Common dividends pertaining to our quarterly financial results are generally declared and paid in the immediately following quarter.

In 2012, we paid dividends to the Province in the amount of $370 million, consisting of $352 million in common dividends and $18 million in preferred dividends. In 2011, we paid dividends in the amount of $168 million, consisting of $150 million in common dividends and $18 million in preferred dividends.

In 2012, cash dividends per common share were $3,523, compared to $1,500 per common share in 2011. Cash dividends per preferred share were $1.375 in each of 2012 and 2011.

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 to our shareholder.

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 (millions of dollars)	**2012**	**2011**	**$ Change**	**% Change**
Transmission	776	810	(34)	(4)
Distribution	671	628	43	7
Other	7	9	(2)	(22)
	1,454	1,447	7	-

Transmission

Transmission capital expenditures decreased by $34 million, or 4%, to $776 million in 2012, compared to 2011. Investments to expand and reinforce our transmission system were $313 million, representing a decrease of $103 million from last year. The majority of our expenditures were made on inter-area network projects to support the Province's supply mix objectives for generation, although we continue to make significant investments in load customer connection and local area supply projects to address growing loads. The 2012 decrease in our expenditures results from the completion of several large projects in 2011. Major inter-area network projects completed and put into service in 2011 included the installation of SVCs at our Nanticoke, Detweiler, Porcupine and Kirkland Lake transformer stations. Also contributing to the reduction in expenditures were lower expenditures in 2012 related to our Woodstock Area Transmission Reinforcement Project to increase capacity and ensure supply reliability in the Woodstock area, and our Bruce to Milton Transmission Reinforcement Project connecting refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. These projects were successfully put into service in March and May of this year, respectively. The impact of the reductions in expenditures in both periods was partially offset by increases in our expenditures resulting from load customer connection and local area supply projects progressing into their build phases, and investments in our transformer stations related to the ADS Project, which supports clean DG connected to our distribution system consistent with the GEA.

On June 18, 2012, our subsidiary Hydro One Networks entered into an agreement with the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively known as the Saugeen Ojibway Nation (SON). The agreement contemplates a new Limited Partnership (LP) to hold only the lines and related land rights of our Bruce to Milton Transmission Reinforcement Project. The carrying value of these assets is expected to be approximately $600 million when they are transferred to the LP in late 2013. Under the terms of our agreement, the SON will be eligible to purchase a non-controlling equity interest in the LP at fair value. The LP is anticipated to become a rate-regulated entity under the jurisdiction of the OEB. Transfer of our assets to the LP and subsequent sale of an equity interest to the SON are both subject to the receipt of future regulatory approvals from the OEB. On December 18, 2012, the SON, Hydro One Networks and Hydro One signed a Letter Agreement in connection with the establishment of the LP. The Letter Agreement addresses, among other things, the terms of the LP Agreement to be entered into on closing and the terms on which Hydro One Networks will operate the Bruce to Milton Line on behalf of the LP. The closing is conditional on certain regulatory approvals and tax rulings.

Our local area supply project expenditures include investments in our Switchyard Reconstruction Project at our Burlington Transformer Station, which will address aging infrastructure to increase the load supply capacity and to ensure reliability of supply to customers in the area. The project successfully went into service on December 21, 2012. We continue to invest in our Midtown Electricity Infrastructure Renewal Project to replace aging cable and overhead line facilities and to provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west. Work is progressing at our Hearn Switching Station to rebuild an existing switchyard that has reached its end-of-life. This project will also increase short circuit capability to accommodate future connection of renewable generation in central and downtown Toronto.

Significant expenditures within our load customer connection projects include investments to build our Commerce Way Transformer Station, a new load supply station in the City of Woodstock that was partially put into service on December 19, 2012. This project will provide additional transformation and line capacity to address load growth issues in the Woodstock area.

Expenditures to sustain our existing transmission system were $392 million in 2012, representing an increase of $57 million compared to 2011. During the year, we made significant investments in the refurbishment and replacement of end-of-life equipment, including end-of-life oil circuit breakers, switches, insulators and protections at our Abitibi Canyon switching station, and deteriorated autotransformers at our Trafalgar and Claireville transformer stations. Of these projects, the autotransformer at our Trafalgar transformer station and one of two at our Claireville transformer station were successfully put into service this year. During the year, we also experienced an increase in replacements for end-of-life protection and control equipment.

Our other transmission capital expenditures were $71 million in 2012, representing an increase of $12 million compared to 2011. The majority of these increased expenditures were related to fleet acquisitions and to information technology (IT) investments.

Distribution

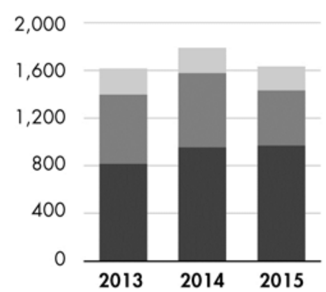
Our distribution capital expenditures increased by $43 million, or 7%, to $671 million in 2012, compared to 2011. Capital investments to expand and reinforce our distribution network were $284 million in 2012, representing an increase of $15 million compared to 2011. We experienced increases in 2012 related to our continued investments in our ADS Project, a multi-year initiative to identify, deploy, analyze and assess equipment and applications to modernize our distribution system. The ADS Project will protect distributed generators from power interruption and is anticipated to improve outage restoration, reduce construction and ongoing maintenance costs, and reduce power loss as it flows across the electricity grid. Increased capital expenditures in 2012 were also due to investments related to our other distribution projects and upgrades to safely and reliably accommodate additional renewable energy, and to higher volumes of new customer connections and upgrades, partially offset by reduced expenditures within our Smart Meter Project as it nears completion.

Expenditures to sustain our distribution system network were $245 million in 2012, representing an increase of $5 million compared to 2011. The increase in our sustainment program was primarily impacted by increased work accomplished within our lines and distribution station refurbishment programs, as well as higher expenditures related to the strategic purchase of power transformers compared to the prior year. These impacts were partially offset by lower storm restoration work given lower storm activity in 2012 compared to two major storms in Ontario in 2011.

Other distribution capital expenditures were $142 million in 2012, representing an increase of $23 million, compared to 2011. The majority of these expenditures were related to the CIS phase of our enterprise-wide information system replacement and improvement project. In addition to replacing end-of-life systems, this implementation will result in process improvements that are expected to provide many benefits, including enhancements to customer satisfaction through reduced call times and first call resolution of issues given faster availability of information. Productivity savings are anticipated to result from performance improvements, consolidation of systems, and decommissioning of over a dozen legacy systems.

Future Capital Expenditures

Our capital expenditures for 2013 are budgeted at approximately $1,600 million. Our 2013 capital budgets for our transmission and distribution businesses are about $1,000 million and $600 million, respectively. Consolidated capital expenditures are expected to be approximately $1,750 million in 2014 and $1,650 million in 2015. These expenditure levels reflect meeting the sustainment requirements of our aging infrastructure. Our sustainment program is expected to be approximately $800 million in 2013, $950 million in 2014 and $1,000 million in 2015. Our development projects include the ADS, inter-area network upgrades that reflect supply mix policies, local area supply requirements, and requirements to enable DG. Our development expenditures are expected to be approximately $600 million in 2013, $600 million in 2014, and $450 million in 2015. These development investments also reflect customer demand work. Other capital expenditures are expected to be approximately $200 million in each of 2013, 2014 and 2015. These expenditures include investments to replace our end-of-life customer billing system and smaller projects related to the continued realization of increased productivity from our enterprise-wide SAP information system.



Future Capital Expenditures
(CAD $ millions)

Transmission

Transmission capital expenditures include significant investments to manage the replacement and refurbishment of our aging transmission infrastructure in order to ensure a continued reliable supply of energy to customers throughout the province. Our investment plan includes sustainment investments to replace end-of-life air blast circuit breakers and switchgear, high-voltage underground cable, and aging power transformers and to comply with North American Electricity Reliability Corporation cyber security requirements. These sustaining investments are necessary to ensure that we continue to meet all regulatory, compliance, safety and environmental objectives.

Major capital investments include our Oshawa Area Transformer Station Project to install additional auto-transformer capacity at our proposed Clarington Transformer Station, for which the OPA has requested that Hydro One develop an implementation plan and initiate work. Planning and environmental studies are currently being undertaken for this project. Investments also include our Midtown Electricity Infrastructure Renewal Project that will provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west, our SVC installation to be completed at our Milton station, and our project to rebuild the switching station at our Hearn Transformer Station, which is expected to be completed by 2014. Transmission investments for ADS and requirements to enable DG are also included in the investment plan. The Hearn Transformer Station Project, when combined with four other transformer station upgrades, will collectively enable up to 600 MW of new transmission capacity.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work for specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy. On April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at ten of 15 transformer stations. These upgrades are substantially complete. Expenditures for these upgrades have been recorded within operation, maintenance and administration (see "Regulation – Long-Term Energy Plan"). Two of the three priority specified transmission projects are reflected in our budgeted capital expenditures. The West of London Transmission Upgrade Project generally requires restringing conductor on existing towers along an existing right-of-way and will enable the connection of additional renewable generation in the west of London area. The Southwestern Ontario Reactive Compensation Priority Project will increase the transmission capability of the Bruce transmission system. We are awaiting direction on the third priority project from the OPA (see "Regulation – Long-Term Energy Plan").

In August 2010, the OEB introduced a framework for competitive designation for the development of eligible transmission projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansions under the OEB's competitive framework. We do not plan to undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

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. Projects are also dependent on the timing and level of generator contributions for enabling facilities.

Distribution

Distribution capital expenditures include investments 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 are continuing investments to replace end-of-life equipment and components, implement ADS as part of this renewal and a focus on wood pole replacements to maintain reliability. In addition, we will continue to address customer demand projects through connectivity for DG, the demand for new load connections, trouble calls, storm restoration and system capability reinforcement.

Distribution development expenditures over the period are primarily related to the development of an ADS system and related grid modernization standards, customer demand work such as connections and upgrades, work to facilitate DG connections, including station upgrades, protection and control, new lines and some contestable work for which we receive capital contributions. During the 2013 and 2014 periods, we expect to manage a significant number of projects throughout the province to address load growth and the stress on our system components.

DG expenditures are based on our estimate of the number of anticipated connections, which have been reduced based on the experience gained since 2009 and changes that have occurred to the FIT Program. The budget only reflects expenditures for projects with FIT and microFIT Program contracts from the OPA that are expected to connect to our distribution system.

In 2013, the ADS Project will look at optimizing outage response through more effective dispatch, automation to isolate faults where needed and the dynamic regulation of voltage to reduce losses.

Summary of Contractual Obligations and Other Commercial Commitments

There are no off-balance-sheet arrangements that have, or are reasonably likely to have, a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments.

December 31, 2012 (millions of dollars)	**Total**	**2013**	**2014/2015**	**2016/2017**	**After 2017**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	8,460	600	1,300	1,100	5,460
Long-term debt – interest payments	7,336	410	735	651	5,540
Pension[1]	330	158	172	-	-
Environmental and asset retirement obligations[2]	313	30	73	40	170
Inergi LP (Inergi) outsourcing agreement[3]	287	136	151	-	-
Operating lease commitments	53	10	15	14	14
Total Contractual Obligations[4]	16,779	1,344	2,446	1,805	11,184
Other Commercial Commitments *(by year of expiry)*					
Bank line[5]	1,250	-	-	1,250	-
Letters of credit[6]	150	150	-	-	-
Guarantees[6]	326	326	-	-	-
Total Other Commercial Commitments	1,726	476	-	1,250	-

1 Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2013 and 2014 minimum contributions are based on an actuarial valuation filed in May 2012 and effective December 31, 2011. Based on expected levels of 2012 pensionable earnings, our total 2012 annual pension contributions were approximately $160 million. Future minimum contributions beyond 2014 will be based on an actuarial valuation effective no later than December 31, 2014, and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2014 are not estimable at this time.

2 We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl (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 materials from our facilities and the decommissioning and removal of certain switching stations. The expenditure pattern reflects our planned work programs for the periods.

3 On March 1, 2002, Inergi began providing a range of services to us for a ten-year period, including IT, customer care, supply chain and certain human resources and finance services. On May 1, 2010, consistent with the terms of the contract, our company extended the Master Services Agreement with Inergi for a further three-year period, to expire on February 28, 2015. Given the complexities involved, we have begun developing a plan of action for end-of-term and anticipate working towards a request for proposal in 2013. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

4 In addition, our 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 is considered individually material, and the majority do not extend beyond December 31, 2013.

5 In support of our liquidity requirements, we have a $1,250 million revolving standby credit facility with a syndicate of banks that matures in June 2017.

6 We currently have outstanding bank letters of credit of $127 million relating to retirement compensation arrangements. On April 27, 2012, our highest credit rating declined from the "Aa" category to the "A" category. Based on this credit rating category, we began providing prudential support to the IESO in the form of letters of credit, the amount of which is calculated based on forecasted monthly power consumption. As at December 31, 2012, we provided letters of credit to the IESO in the amount of $22 million to meet our current prudential requirement. The other $1 million pertains to operating letters of credit. 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 $0.7 million.

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 Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Interest associated with this debt is recorded under financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration expense on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchase payments made to the IESO, which is a related party by virtue of its status as an agency of the Province. The year-over-year changes related to these amounts are described more fully in the 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 PILs and some of our property 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

Our load, based on normal weather patterns, is expected to marginally decline in 2013 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 1.3%, with the commercial and industrial sectors slightly outperforming the residential sector. The load impacts of CDM and embedded generation are expected to have a negative impact on load growth of approximately 1.1% and 0.3%, respectively. On the whole, our load is expected to decline by about 0.1% in 2013. Our approved revenue requirement for 2013 has taken the expected load decline into account. 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 the revenue requirements upon which our rates are based. The first component impacted by interest rates is our ROE. The OEB-approved adjustment formula for calculating ROE 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%. All other things being equal, we estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our ROE would reduce Hydro One Networks' transmission and distribution businesses' results of operations by approximately $19 million and $10 million, respectively. As interest rates decline, there is more risk of a decline in our net income. 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, general outline agreements, and vendor alliances and we also 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 at December 31, 2012, 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 2012, we continued issuing sufficient cost-effective debt financing through the MTN Program in the Canadian capital markets and we arranged sufficient available liquidity. Economic conditions were challenging in 2012 and we expect they will remain challenging in 2013.

Pension

In 2012, we contributed approximately $160 million to our pension plan and incurred $207 million in net periodic pension benefit cost. An actuarial valuation filed in May 2012 and effective December 31, 2011 did not result in significant changes to our 2012 required contributions or our 2012 net periodic benefit cost. Actuarial valuations are minimally required to be filed every three years. We currently estimate our total annual pension contributions to be approximately $160 million for 2013 and 2014, based on the projected level of pensionable earnings and the same actuarial valuation effective December 31, 2011. Future minimum contributions beyond 2014 will be based on the actuarial valuation effective no later than December 31, 2014. Our pension plan experienced positive returns of about 9.19% in 2012. Our pension obligation is impacted by interest rates. The 1% decrease in the discount rate, from 5.25% at December 31, 2011 to 4.25% at December 31, 2012, resulted in an increase in the pension obligation of $862 million and an increase to our post-retirement and post-employment benefit obligation of $241 million. No new benefits were introduced and over the last number of years benefits have been reduced through re-negotiations with certain of our unions as well as our management employees.

RISK MANAGEMENT AND RISK FACTORS

We have an Enterprise Risk Management (ERM) 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 goals. Our ERM program helps us to better understand uncertainty and its potential impact on our strategic goals. It sets out the uniform principles, processes and criteria for identifying, assessing, evaluating, treating, monitoring and communicating risks across all lines of business. It supports our Board of Directors' corporate governance needs and the due diligence responsibilities of senior management.

While our philosophy is that risk management is the responsibility of all employees, the Board of Directors annually reviews our company's risk tolerances, risk management policies, processes and accountabilities. Twice per year, the Board of Directors reviews our risk profile, which is the list of key risks prepared by senior management, that represents the greatest threats to meeting our strategic objectives. The Audit and Finance Committee of our Board of Directors annually reviews the status of our internal control framework.

Our President and Chief Executive Officer (CEO) has ultimate accountability for risk management. Our Leadership Team provides senior management oversight of our risk portfolio and our risk management processes. The leadership team provides direction on the evolution of these processes and identifies priority areas of focus for risk assessment and mitigation planning.

Our Chief Administration Officer and Chief Financial Officer (CAO and CFO) is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. The CAO and CFO has specific accountability for ensuring that enterprise risk management processes are established, properly documented and maintained by our company.

Our senior managers, line and functional managers are responsible for managing risks within the scope of their authority and accountability. Risk acceptance or mitigation decisions are made within the risk tolerances specified by the head of the subsidiary or function.

The CAO and CFO provides support to the Audit and Finance Committee of our Board of Directors, the President and CEO, the senior management team and key managers within our company. This support includes developing risk management frameworks, policies and processes, introducing and promoting new techniques, establishing risk tolerances, preparing annual corporate risk profiles, maintaining a registry of key business risks and facilitating risk assessments across our company. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems. Starting in 2013, our Board of Directors has taken on an enhanced role in our governance structure. Each committee of the Board of Directors will take accountability for reviewing specific risks of our company.

Key elements of our ERM Program enable us to identify, assess and monitor our risks effectively. These include having an ERM policy and framework which communicates our philosophy and process for risk management across our company. A discussion of risks is an integral part of each line of business' planning documents on an annual basis. Risk identification is also considered as part of each business case for investments. Finally, discrete risk assessments and workshops are performed for specific lines of business, key projects and various profiles, such as customer relationships and regulatory compliance.
In order to drive consistency throughout our risk identification and risk management processes, we use a standard list of risk sources known as our risk universe. These sources are maintained in a single database that provides a consistent basis for risk identification and classification and serves as a repository for our risk assessments. All risk assessments in our company start with this risk universe. We also use standard risk criteria, which establish the metrics and terminology used for assessing and communicating on risks, and help ensure a consistent basis for our risk assessments and risk evaluations across all lines of business. Risk criteria include formally established risk tolerances and standard scales for assessing the probability of a risk materializing and the strength of controls in place to mitigate them.

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 our company, among other entities, 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. Our 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, including any potential outcomes arising out of the recommendations of the Ontario Distribution Sector Review Panel's report, the Province's ownership of Ontario Power Generation Inc., 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 materially falls below projected levels, our net income 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. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

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.

In Ontario, the Market Rules mandate that we comply with the reliability standards established by North American Electric Reliability Corporation and Northeast Power Coordinating Council Inc. As a result, we will be required to comply with the Federal Energy Regulatory Commission's definition of "bulk electric system" unless we are granted an exemption which will allow the application of the new definition in a cost-effective manner. We will look for recovery for costs incurred in meeting the definition in our rates; however an adverse decision on an exemption for recovery of costs could have an 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 2013 and 2016, including $600 million maturing in 2013 and $750 million maturing in 2014. We plan to incur capital expenditures of approximately $1.6 billion in 2013 and $1.8 billion in 2014. 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 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 with First Nations and Métis. Obtaining OEB and/or environmental assessment approvals and carrying out these processes may also be impacted by opposition to the proposed site of transmission investments which could 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, in the absence of a government directive, 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. This could have a material 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 programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, such as outage planning with the IESO and transmission-connected customers, funding approval by the OEB, and supply chain availability for equipment suppliers and consulting services. In addition, opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities.

Adjustments to accommodate these external dependencies have been made in our planning process, and we are focused on overcoming these challenges to execute our work programs. 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.

Workforce Demographic Risk

By the end of 2012, approximately 18% of our employees were eligible for retirement and by 2013 there could be up to 20% 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 are therefore focused on earlier identification and more rapid development of staff who demonstrate management potential. Moreover, we must also continue to advance our technical 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 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.

Under applicable regulations, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We record an asset retirement obligation for the present value of the estimated future expenditures. The estimates are based on an external, expert study of the current expenditures associated with removing such materials from our facilities. Actual future expenditures may vary materially from the estimates used for the amount of the asset retirement obligation.

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 IT 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 mitigate this risk through various methods including the use of security event management tools on our power and business systems, by separating our power system network from our business system network, by performing scans of our systems for known cyber threats and by providing company-wide awareness training to our personnel. We also engage the services of external experts to evaluate the security of our IT infrastructure and controls. We perform vulnerability assessments on our critical cyber assets and we ensure security and privacy controls are incorporated into new IT capabilities. Although these security and system disaster recovery controls are in place, there can be no guarantee that there will not be system failures or security breaches. Upon occurrence, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on our company.

We are currently in the process of a planned phased replacement of key enterprise IT systems. The last phase of this project is underway and will replace our existing billing and customer system with a new CIS. With projects of this size and complexity, there is risk to the Company if the resulting solution encounters performance problems or calculation errors. Any such system problems could have a material adverse effect on our company. To mitigate this risk, extensive testing and user training is taking place. Testing includes performance, system integration, parallel billing (comparing legacy system bill calculation to the new system), and operational/business readiness. Since this system directly impacts our end customers, stringent test exit criteria must be met prior to placing it into production.

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, 2011 and was filed in May 2012. Our company contributed $148 million in respect of 2011 and approximately $160 million in respect of 2012 to its pension plan to satisfy minimum funding requirements. An additional contribution of $3.8 million was also made in 2011 to complete the funding associated with the partial plan wind-up. Contributions beyond 2012 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. The OEB-approved adjustment formula for calculating ROE 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 used in determining our rate of return would reduce our Transmission Business' net income by approximately $19 million and our Hydro One Networks' 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 counterparty 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 counterparty default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counterparties. 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 have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff hired after November 2005 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, 2013 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.

First Nation and Métis Claims Risk

Some of our current and proposed transmission and distribution lines may traverse lands over which First Nations and Métis have aboriginal, treaty or other legal claims. Although we have a recent history of successful negotiations and consultations with First Nations and Métis in Ontario, some communities and/or their citizens have expressed an increasing willingness to assert their claims through the courts, tribunals, or by direct action, which in turn can affect business activities. As a result, there exists uncertainty relating to business operations and project planning which could have an adverse effect on our company.

Risk from Transfer of Assets Located on Reserves

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 Reserves. Currently, OEFC holds legal title to these assets and we manage them until we have obtained necessary authorizations to complete the title transfer. To occupy Reserves, we must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, we must negotiate an agreement (in the form of a Memorandum of Understanding) with the First Nation, OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. It is difficult to predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. However, we anticipate that the amount will exceed the approximately $943,000 that we paid in 2012. OEFC will continue to hold these assets until we are able to negotiate agreements with First Nations and occupants. If we cannot reach satisfactory agreements and obtain federal permits, we may have to relocate these assets to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary 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, effectively renewing the arrangement until February 28, 2015. If the agreement with Inergi 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, which could have an adverse effect on our company.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our Consolidated 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 Consolidated Financial Statements:

Regulatory Assets and Liabilities

At December 31, 2012, regulatory assets amounted to $3,127 million and these amounts principally relate to regulatory offsets to pension, deferred income tax, post-retirement and post-employment benefits and environmental liabilities, which are anticipated to be recovered through rates over time. We have also recorded regulatory liabilities amounting to $221 million as at December 31, 2012. These amounts pertain primarily to OEB deferral and variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the relevant amounts have been approved for inclusion in the rate-setting process by the OEB or if such approval is judged to be probable by management. If management judges that it is no longer probable that the OEB will include a regulatory item 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 now 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% is 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 3.57% to 4.87%, depending on the appropriate rate for the period when the particular obligation was recorded. Consistent with the current requirements of Environment Canada's PCB regulations, 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 in effect in the period when each obligation was originally recorded.

Recording a liability for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination; the number of assets to be inspected, tested and mitigated; oil volumes; contamination levels of equipment that may have PCBs; and the timing of work. 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 requirements 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 current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Regulatory changes are reflected when enacted. 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 2012 were approximately $160 million, based on an actuarial valuation effective December 31, 2011. Contributions after 2014 will be based on an actuarial valuation effective no later than December 31, 2014, and will depend on investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the Consolidated Financial Statements on an accrual basis. The discount rate used to calculate the accrued benefit obligation, on an accrual accounting basis, is calculated differently from what would be used to determine the funding requirement, and 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, 2012 declined to 4.25% from 5.25% used at December 31, 2011, in conjunction with decreases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities for accounting purposes. We also record employee future benefit costs other than pension on an accrual accounting 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. There were no changes in benefits afforded to employees.

The assumed return on pension plan assets of 6.25% 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 was 60% equities, 35% fixed income and 5% in alternative assets consisting of real estate and infrastructure. 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 2012, the return on pension plan assets of 9.19% was higher than this long-term assumption and was higher than in 2011.

Yields on AA corporate bonds declined by approximately 80-100 basis points between December 31, 2011 and December 31, 2012. Based on the duration of the plan's liabilities, discount rates would be 4.25% 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 accounting purposes as at December 31, 2012 was 4.25%.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has decreased from 2.0% per annum as at December 31, 2011 to approximately 1.90% per annum as at December 31, 2012. 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 reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for liability valuation purposes as at December 31, 2012.

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 $17 million per year and an increase in the year-end obligation of about $246 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 and intangible 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 part of the cost of fixed and intangible assets.

Asset Impairment

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 need to 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 within any of our businesses.

TRANSITION TO US GAAP

Accounting Framework for External Reporting

In 2011, the OSC and our Board of Directors approved our application to adopt US GAAP as the basis for our accounting, external financial reporting and periodic securities filings, without becoming a Securities and Exchange Commission (SEC) registrant, for our 2012, 2013 and 2014 fiscal years. As a result, our Consolidated Financial Statements and accompanying notes as at, and for the year ended, December 31, 2012 have been prepared in accordance with US GAAP. These are our first US GAAP annual Consolidated Financial Statements. Our first US GAAP unaudited interim Consolidated Financial Statements were as at, and for the three months ended, March 31, 2012.

Our company's Consolidated Financial Statements were prepared in accordance with Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook until December 31, 2011. Canadian GAAP differs in some areas from US GAAP as disclosed in the reconciliation to US GAAP included in Note 24 to the annual Consolidated Financial Statements as at, and for the year ended, December 31, 2012. Descriptions of the effect of the transition from Canadian GAAP to US GAAP on our financial position, financial performance and cash flows as at, and for the year ended, December 31, 2011 are also provided in Note 24 to our annual Consolidated Financial Statements for the year ended December 31, 2012. The accounting policies set out in the annual Consolidated Financial Statements for the year ended December 31, 2012 have been consistently applied to all the periods presented. The comparative figures in respect of 2011 were retrospectively restated effective January 1, 2011 to reflect our adoption of US GAAP.

Accounting Framework for Rate Setting

Consistent with the OSC's decision to approve our adoption of US GAAP, two of our subsidiaries, Hydro One Networks and Hydro One Remote Communities requested that the OEB approve the adoption of US GAAP as the basis for future rate setting and regulatory accounting and reporting in place of its standard modified IFRS basis. The OEB approved Hydro One Networks' request to adopt US GAAP for its regulated transmission and distribution businesses, and approved Hydro One

Remote Communities' request to adopt US GAAP as its approved basis for rate setting, all effective January 1, 2012. We did not make a request to adopt US GAAP for rate-setting purposes on behalf of our subsidiary, Hydro One Brampton Networks. Our subsidiary Hydro One Brampton Networks has deferred its adoption of modified IFRS until the fiscal year beginning January 1, 2014, as allowed by the Canadian Accounting Standards Board. Currently, Hydro One Brampton Networks will continue to have its rates set based on Part V of the CICA Handbook until it begins reporting under modified IFRS.

Debt Covenants

None of our financial covenants were impacted by our conversion to US GAAP.

Internal Controls over Financial Reporting and Disclosure Controls and Procedures

Our transition to US GAAP did not result in any significant revisions to our internal controls over financial reporting and disclosure controls and procedures.

Financial Reporting Expertise

Given the similarities between US GAAP and Canadian GAAP for our company, there has also been no significant impact from the transition to US GAAP with respect to financial reporting expertise. Our US GAAP training efforts have been focused on specific areas of difference between the two accounting frameworks and these efforts have been targeted to specific finance staff, senior executive management and the Audit and Finance Committee of our Board of Directors. We continue to provide additional training to our other finance and operational staff, concentrating on communicating the key differences between Canadian and US GAAP at a level of detail that is appropriate to meet their respective needs. During 2013, we will continue to focus our US GAAP training on new accounting and reporting developments and on emerging issues.

Information Systems

Given the similarities between US GAAP and Canadian GAAP, we did not experience any significant impacts from the transition to US GAAP with respect to our information systems.

IFRS

Prior to our adoption of US GAAP as the basis for our accounting, external financial reporting and periodic securities filings, we had planned to adopt IFRS effective January 1, 2012, with comparative restatement of our 2011 results. Accordingly, by mid-2011, we had substantively completed our four-phase IFRS Conversion Project, which included separate diagnostic, design and planning, solution development, and implementation phases. Our IFRS conversion project involved, among other initiatives, a detailed assessment of the effects of IFRS on our financial statements, a review and upgrade of our information systems to meet IFRS requirements, an assessment of our internal controls over financial reporting and disclosure controls and processes, as well as training of our key finance and operational staff.

As a result of our 2011 decision to adopt US GAAP, our IFRS Conversion Project efforts were effectively halted. However, our IFRS conversion work has been, and will continue to be, managed in such a way that it can effectively be restarted if a future transition to IFRS is required. We continue to monitor major accounting developments arising from initiatives of the international standard setter, particularly as several major projects are joint efforts with the US Financial Accounting Standards Board.

Training of our key finance and operational staff commenced in 2007, and continues on a reduced but ongoing basis, as we have certain subsidiaries that are required to prepare their own separate financial statements in accordance with IFRS. IFRS training was also previously provided to our Audit and Finance Committee and senior executive management. In 2013, we will continue to monitor new IFRS accounting and reporting developments and emerging issues and will provide IFRS training to specific staff as applicable.

Our company has the customary financial 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 international standard setting initiatives, including the International Accounting Standards Board's (IASB) Rate

Regulated Accounting Project, a potential future adoption of IFRS could result in changes to our financial position and increased volatility in our results of operations that could impact our debt covenants. We continue to monitor the potential impact that an IFRS conversion could have under various scenarios.

As part of a company-wide information systems improvement project, many of our major financial systems were replaced in 2008 and 2009. Our new financial systems were designed with maximum flexibility given the uncertainty of the outcome of certain impactive IASB projects. Our financial systems have the ability and capacity to handle current accounting and reporting processes in accordance with IFRS, should that be required in the future.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING (ICFR)

To optimize our customer service operations, we have started the final major phase of our planned SAP enterprise-wide information system by initiating our CIS Project. This new system will increase productivity by replacing multiple legacy applications currently providing service to our distribution customers and key constituents for billing, customer contacts, field services, settlements and customer choice administration. With the design phase complete, the CIS Project is currently in the system integration phase. Internal controls have been documented and will be tested for adequacy and effectiveness with any remediation effort to be completed prior to the go-live date in 2013. In addition to the benefits associated with our CIS, we continue to leverage our other SAP enterprise systems to gain other productivity improvements.

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, 2012, 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, 2012. Further, our Certifying Officers have also certified that our ICFRs have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of our company's ICFR, our Certifying Officers concluded that our ICFR was effective as at December 31, 2012.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2012, 2011 and 2010. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statements of Operations

Year ended December 31 (millions of dollars, except amounts per share)	**2012**	**2011**	**2010**[1]
Revenues	5,728	5,471	5,124
Net income	745	641	591
Basic and fully diluted earnings per common share	7,280	6,228	5,727
Cash dividends per common share	3,523	1,500	100
Cash dividends per preferred share	1.375	1.375	1.375

Consolidated Balance Sheets

December 31 (millions of dollars)	**2012**	**2011**	**2010**
Total assets	20,811	18,836	17,344
Total long-term debt	8,479	8,008	7,783

1 Based on Canadian GAAP. US GAAP results would not differ significantly.

OUTLOOK

To achieve our mission and vision to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers, we will continue to concentrate on our strategic objectives of safety, customer satisfaction, continuous innovation, reliability, protection of the environment, employee engagement, shareholder value and productivity and cost-effectiveness. Given the nature of the work undertaken by our employees and contractors, safety remains our top priority. We will continue to focus on creating an injury-free workplace and maintaining public safety through several health and safety initiatives.

We will continue to focus our efforts to improve our customers' satisfaction by meeting the unique needs of our diverse customer base through dialogue to understand their needs. We will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers more capability to manage their own costs. Most importantly, we are focused on becoming the customer's trusted advisor by providing access to specialized energy conservation teams to discuss the customer's opportunities to lower consumption, and through the use of a special team of agents to handle distributed generator inquiries and requirements.

Our assets are in the midst of a demographic change with an increasing proportion of assets reaching end-of-life and an increasing average asset age. Our focus is to address aging infrastructure, and to make needed asset replacement and maintenance investments, to maintain current and future system reliability for customers, within the policy set by the OEB. We will invest in technology that will provide us with real time asset condition and performance data giving us the visibility to make asset optimization life-cycle decisions, and opportunities through planning and scheduling data to improve materials procurement and to deploy work crews to better manage work programs to meet customer needs.

It is expected that the implementation of new asset management tools, such as Asset Analytics and Asset Investment Planning, will enhance risk-based investment planning, which considers such factors as asset condition, safety, performance, system function, customer impact, and statutory requirements allowing for targeted investment.

We will also continue to strive for productivity through efficiency and effective management of costs, which is key to achieving value for our customers and our shareholder.

Over the last four years, we have replaced most of our core information technology systems with an enterprise-wide IT system. We will leverage this investment as a platform for further effectiveness and efficiency gains, including enhancements in strategic sourcing. Further development of the existing IT platform will provide tools which are being developed to allow our company to effectively plan and reprioritize work and integrate customers' needs into multi-year investment plans. The outcomes are consistent with the OEB's direction in its new Outcomes-Based Approach to regulation.

We will be implementing the new CIS in 2013 that will improve customer service and corporate productivity by allowing the earlier investments in SAP to operate as an integrated platform. In addition, the first elements of the next generation of work delivery to be introduced through the Workflow of the Future Program in 2013 and 2014, and the use of information within the SAP systems, are expected to improve field-level productivity.

We are planning significant investments in transmission and distribution infrastructure and we will continue to focus on the operating and economic performance of our core utility operations in the provision of safe, cost-effective and reliable electricity delivery services to our customers, and in providing increasing enterprise value to the people of the province of Ontario. Productivity, value for money and improved employee and customer communications will be key areas of focus. We will continue to connect and support DG and investments made consistent with the LTEP.

Significant opportunity resides with smart meters and the proliferation of an ADS, including energy efficiency, demand response and distributed-resources technologies. We will invest in the development of an ADS and related grid modernization standards, customer demand work (connections and upgrades), smart meters, DG connections, including station upgrades, protection and control, new lines and some contestable work, for which the Company will receive capital contributions. There is little flexibility to reduce this work as most of it is customer demand driven.

As part of our new ADS, a new DMS will provide a monitoring and centralized control capability similar to that which already exists in the transmission system, and in selected areas of the distribution system. The new DMS was introduced in the Owen Sound pilot area and it will be expanded over time, as warranted. Future enhancements will also integrate the

Outage Response Management System with the Advanced Meter Infrastructure (i.e. smart meters) and with the DMS, to reduce System Average Interruption Duration Index and System Average Interruption Frequency Index.

The actual timing and expenditures in our business 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.

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 by ensuring that environmental factors are considered in making our business decisions.

Key enablers of the successful implementation of our work programs are our human and material resourcing strategies. Our human resource strategy is focused on hiring through our apprenticeship program and our association with universities, colleges and our unions, as well as skills development and retention, including earlier identification and more rapid development of staff who demonstrate management potential. Effective use of human resources and ensuring correct skills will be critical to attaining the balance between meeting the asset needs and mitigating rate impact on the customer. Although our work program is assumed to grow moderately over the 2013 and 2014 years, no increase in regular staff numbers is anticipated over that period. With regard to materials, we are seeing a need for 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. We have considered and will continue to consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis. Our plan does not include funding for LDC acquisitions or assume any disposition of our service territory. These opportunities will be managed as they arise. Our plan also does not incorporate any projects related to competitive transmission. However, as leaders in the sector, we plan to bid on key projects. The OEB notes in its *Framework for Transmission Project Development Plans* that where projects are otherwise equivalent or close in other factors, information such as socio-economic benefits, including First Nations involvement, could prove decisive in a competitive bid. As such, First Nations involvement in competitive bids is likely to become more prevalent.

APPOINTMENT OF CARMINE MARCELLO

On November 14, 2012, our Board of Directors appointed Carmine Marcello to the role of President and Chief Executive Officer, effective January 1, 2013. Mr. Marcello assumes his responsibilities following the planned retirement of outgoing President and Chief Executive Officer, Laura Formusa. Mr. Marcello has over 25 years' experience with our company as a senior executive, strategic planner and advisor on transmission and distribution utility processes in the electric utility industry.

APPOINTMENT OF YEZDI PAVRI

On December 6, 2012, Yezdi Pavri was appointed to our Board of Directors. Mr. Pavri is a Chartered Accountant and a former Vice-Chairman of Deloitte Canada. Mr. Pavri currently holds the position of Chair of the Board of Trustees of the United Way of Toronto.

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, including our strategic objectives; statements regarding our transmission and distribution rates; statements regarding load changes and associated impacts; statements regarding CDM programs and targets; the estimated impact of changes in the forecasted long-term Government of Canada bond yield (used in determining our regulated rate of return) on our results of operations; statements related to economic conditions; expectations regarding energy-related revenues and profit and their trend; statements related to the GEA, the IPSP and the Ministry's LTEP and Supply Mix Directive, including additional investments arising therefrom and the timing and content of OPA recommendations; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility; expectations regarding our financing activities; statements regarding our maturing debt; statements regarding our ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives and their completion dates; expectations regarding the recoverability of large capital expenditures; statements regarding expected future capital and development expenditures, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commercial commitments; statements related to the OEB, including the renewed regulatory framework and revenue decoupling; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangement with Inergi; statements relating to US GAAP and our adoption of US GAAP; statements regarding accounting-related international standard setting initiatives, including the potential future adoption of IFRS and its associated impacts as well as our training and conversion plans; statements related to our agreement with the SON; statements related to our outlook including statements regarding our approach to distribution rationalization; and statements related to the FIT program. 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; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission businesses; a stable regulatory environment; 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 Province's Long-Term Energy Plan, including unexpected expenditures arising therefrom;
- the risk that unexpected capital expenditures may be needed to support renewable generation or resolve unforeseen technical issues;
- the risks associated with the impending expiry of our collective agreements with both the Society and the PWU;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risks associated with the OEB's competitive transmission project development planning process;
- 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;
- 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 result of regulatory decisions regarding our revenue requirements, cost recovery and rates;

- 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;
- future interest rates, future investment returns, inflation, and changes in benefits and actuarial assumptions;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the risks associated with information system security, with maintaining a complex information technology system infrastructure, and with transitioning key enterprise IT systems;
- the risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that future environmental expenditures are not recoverable in future electricity rates;
- the risk that it may be determined that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems;
- the risks associated with changes in interest rates;
- the risks of counterparty default on our outstanding derivative contracts;
- the risks associated with current economic uncertainty and financial market volatility;
- the risk that our long-term credit rating would deteriorate;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the risks associated with the fact that some of our current and proposed transmission and distribution lines may traverse lands which First Nations and Métis have aboriginal, treaty or other legal claims;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi is terminated; and
- the impact of the ownership by the Province of lands underlying our transmission system.

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 14, 2013. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
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 United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 14, 2013.

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). The effectiveness of these internal controls is evaluated and findings are reported 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 United States Generally Accepted Accounting Principles. The Independent Auditors' Report 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:

Carmine Marcello

Carmine Marcello	Sandy Struthers
President and Chief Executive Officer	Chief Administration Officer and Chief Financial Officer

HYDRO ONE INC.
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, 2012 and December 31, 2011, the consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years ended December 31, 2012 and December 31, 2011, 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 United States 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 consolidated financial position of Hydro One Inc. as at December 31, 2012 and December 31, 2011, and its consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years ended December 31, 2012 and December 31, 2011 in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
February 14, 2013

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars, except per share amounts)	**2012**	**2011**
Revenues		*(Note 24)*
Distribution (includes $155 related party revenues; 2011 – $155) *(Note 19)*	4,184	4,019
Transmission (includes $1,482 related party revenues; 2011 – $1,372) *(Note 19)*	1,482	1,389
Other	62	63
	5,728	5,471
Costs		
Purchased power (includes $2,409 related party costs; 2011 – $2,427) *(Note 19)*	2,774	2,628
Operation, maintenance and administration *(Note 19)*	1,071	1,092
Depreciation and amortization *(Note 4)*	659	616
	4,504	4,336
Income before financing charges and provision for payments in lieu of corporate income taxes	1,224	1,135
Financing charges *(Note 5)*	358	344
Income before provision for payments in lieu of corporate income taxes	866	791
Provision for payments in lieu of corporate income taxes *(Notes 6, 19)*	121	150
Net income	745	641
Other comprehensive income	1	-
Comprehensive income	746	641
Basic and fully diluted earnings per common share *(dollars) (Note 17)*	7,280	6,228
Dividends per common share declared *(dollars) (Note 18)*	3,523	1,500

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS

December 31 (millions of dollars)	**2012**	**2011**
Assets		*(Note 24)*
Current assets:		
Short-term investments *(Note 12)*	195	228
Accounts receivable (net of allowance for doubtful accounts – $23; 2011 – $18) *(Note 7)*	845	805
Due from related parties *(Note 19)*	154	156
Regulatory assets *(Note 10)*	29	24
Materials and supplies	23	25
Deferred income tax assets *(Note 6)*	18	19
Derivative instruments *(Note 12)*	-	1
Other	22	19
	1,286	1,277
Property, plant and equipment *(Note 8)*:		
Property, plant and equipment in service	22,650	21,008
Less: accumulated depreciation	8,145	7,679
	14,505	13,329
Construction in progress	1,055	1,436
Future use land, components and spares	147	138
	15,707	14,903
Other long-term assets:		
Regulatory assets *(Note 10)*	3,098	1,966
Long-term investment *(Notes 11, 12, 19)*	251	250
Intangible assets (net of accumulated amortization – $305; 2011 – $257) *(Note 9)*	267	224
Goodwill	133	133
Deferred debt costs	34	32
Derivative instruments *(Note 12)*	19	33
Deferred income tax assets *(Note 6)*	14	17
Other	2	1
	3,818	2,656
Total assets	20,811	18,836

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)

December 31 (millions of dollars, except number of shares)	**2012**	**2011**
Liabilities		*(Note 24)*
Current liabilities:		
Bank indebtedness *(Note 12)*	42	39
Accounts payable	140	154
Accrued liabilities *(Notes 6, 14, 15)*	582	575
Due to related parties *(Note 19)*	257	342
Accrued interest	95	85
Regulatory liabilities *(Note 10)*	40	25
Long-term debt payable within one year *(Notes 11, 12)*	600	600
	1,756	1,820
Long-term debt (includes $769 measured at fair value; 2011 – $783) *(Notes 11, 12)*	7,879	7,408
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 14)*	1,416	1,163
Deferred income tax liabilities *(Note 6)*	944	758
Pension benefit liability *(Note 14)*	1,515	779
Environmental liabilities *(Note 15)*	227	235
Regulatory liabilities *(Note 10)*	181	169
Net unamortized debt premiums	23	23
Asset retirement obligations *(Note 16)*	15	15
Long-term accounts payable and other liabilities	25	12
	4,346	3,154
Total liabilities	13,981	12,382
Contingencies and commitments (Notes 21, 22)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 17, 18)*	323	323
Shareholder's Equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 17, 18)*	3,314	3,314
Retained earnings	3,202	2,827
Accumulated other comprehensive loss	(9)	(10)
Total shareholder's equity	6,507	6,131
Total liabilities, preferred shares and shareholder's equity	20,811	18,836

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

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Year ended December 31, 2012 *(millions of dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholder's Equity
January 1, 2012	3,314	2,827	(10)	6,131
Net income	-	745	-	745
Other comprehensive income	-	-	1	1
Dividends on preferred shares	-	(18)	-	(18)
Dividends on common shares	-	(352)	-	(352)
December 31, 2012	3,314	3,202	(9)	6,507

Year ended December 31, 2011 *(millions of dollars)* *(Note 24)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholder's Equity
January 1, 2011	3,314	2,354	(10)	5,658
Net income	-	641	-	641
Other comprehensive income	-	-	-	-
Dividends on preferred shares	-	(18)	-	(18)
Dividends on common shares	-	(150)	-	(150)
December 31, 2011	3,314	2,827	(10)	6,131

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2012**	**2011**
Operating activities		*(Note 24)*
Net income	745	641
Environmental expenditures	(18)	(16)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	589	550
Regulatory assets and liabilities	12	47
Deferred income taxes	(9)	(12)
Asset retirement obligations	-	4
Other	6	9
Changes in non-cash balances related to operations *(Note 20)*	(40)	184
Net cash from operating activities	1,285	1,407
Financing activities		
Long-term debt issued	1,085	700
Long-term debt retired	(600)	(500)
Dividends paid	(370)	(168)
Change in bank indebtedness	3	39
Other	(1)	(4)
Net cash from (used in) financing activities	117	67
Investing activities		
Capital expenditures		
Property, plant and equipment	(1,363)	(1,371)
Intangible assets	(91)	(76)
Other	19	29
Net cash used in investing activities	(1,435)	(1,418)
Net change in cash and cash equivalents	(33)	56
Cash and cash equivalents, beginning of year	228	172
Cash and cash equivalents, end of year	195	228

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act (Ontario)* and is wholly owned by the Province of Ontario (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

These 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 Networks), Hydro One Telecom Inc. (Hydro One Telecom), Hydro One Lake Erie Link Management Inc., and Hydro One Lake Erie Link Company Inc.

Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. These statements are to be read in conjunction with Note 24 – Transition to US GAAP, which discloses information on the Canadian GAAP per Part V of the CICA Handbook (Canadian GAAP) to US GAAP transition and related reconciliations from Canadian GAAP to US GAAP. The results of operations for the year ended December 31, 2011 and the Consolidated Balance Sheet at December 31, 2011 have been restated under US GAAP for comparative purposes. The Company's Consolidated Financial Statements were previously prepared using Canadian GAAP.

Hydro One performed an evaluation of subsequent events for the accompanying Consolidated Financial Statements and notes through to February 14, 2013, the date these Consolidated Financial Statements were issued, to determine whether the circumstances warranted recognition and disclosure of any events or transactions. No such events or transactions were identified.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumptions are made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB or the Province.

Rate Setting

The Company's consolidated Distribution Business includes the separately regulated distribution businesses of Hydro One Networks, Hydro One Brampton Networks, and Hydro One Remote Communities. The OEB has approved US GAAP as the basis for rate setting for Hydro One Networks' Transmission and Distribution businesses and by Hydro One Remote Communities all effective January 1, 2012. Hydro One Brampton Networks' rates are currently set under Canadian GAAP, and are expected to be set under the OEB's modified International Financial Reporting Standards (IFRS) framework commencing in 2015, once its current Incentive Regulation Mechanism (IRM) period is complete.

Transmission

In May 2010, Hydro One Networks filed a cost-of-service application for 2011 and 2012 transmission rates in continued support of the Company's 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.

In December 2010, the OEB approved revenue requirements of $1,346 million for 2011 and $1,658 million for 2012. The approved 2012 revenue requirement was higher than that applied for, reflecting OEB direction to Hydro One to adopt a cost capitalization policy based on modified IFRS. This adjustment was subsequently reversed, when the OEB approved the use of US GAAP for transmission rate-setting purposes beginning January 1, 2012. Consequently, the OEB approved a revenue requirement of $1,418 million for 2012, along with new 2012 uniform transmission rates, with an effective date of January 1, 2012.

Distribution

In 2009, Hydro One Networks filed a cost-of-service application with the OEB for 2011 distribution rates, seeking approval for a revenue requirement of approximately $1,264 million. The application reflected 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 to make investments required by the GEA. In April 2010, the OEB approved a revenue requirement of $1,236 million for 2011. The OEB also approved certain distribution regulatory account balances sought by Hydro One Networks in its application, including retail settlement variance accounts, retail cost variance accounts and smart meters. In November 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. A lowering of the return on equity produced a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement resulted in an average distribution rate increase of approximately 8.7% for 2011. Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for the 2011 rate year.

In 2010, Hydro One Brampton Networks filed a cost-of-service application with the OEB for 2011 distribution rates, seeking approval for a revenue requirement of approximately $63 million. In 2011, the OEB approved a revenue requirement of approximately $60 million for 2011, with an effective date of January 1, 2011. The reduced approved revenue requirement included a reduction to approved operation, maintenance and administration costs. In September 2011, Hydro One Brampton Networks filed an IRM application with the OEB for 2012 distribution rates, with an effective date of January 1, 2012. In January 2012, the OEB released a decision that resulted in a reduction in distribution rates of approximately 13.2% for 2012. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates.

In October 2010, Hydro One Remote Communities filed an IRM application with the OEB for 2011 rates. In March 2011, the OEB approved an increase of approximately 0.4% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2011. In November 2011, Hydro One Remote Communities filed an IRM application with the OEB for 2012 rates. In March 2012, the OEB approved an increase of approximately 1.1% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2012.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses 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 that generally represent amounts that are refundable to future electricity customers. 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 setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments. Short-term investments have an original maturity of three months or less.

Revenue Recognition

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 electricity is transmitted and delivered to customers.

Distribution revenues are recognized on an accrual basis and include billed and unbilled revenues. 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 monthly revenue for a period based on wholesale electricity purchases because customer meters are not generally read at the end of each month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

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. Current legislation provides rate protection for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount or net realizable value, if unbilled. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company’s best estimate of losses on accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the amount billed is not received within 120 days of the invoiced date. Accounts receivable are written off against the allowance when they are deemed uncollectible. The existing allowance for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate income taxes (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) as modified by the *Electricity Act, 1998* and related regulations.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the “more-likely-than-not” recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgement is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

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.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred 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 at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred 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 the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only the ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions received in aid of construction and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project 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, including transformers, circuit breakers and switches.

Distribution

Distribution assets include 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, personal computers, transport and work equipment, tools and other minor 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 land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major administrative computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2007.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate (%)	
	Service Life	Range	Average
Transmission	56 years	1% - 3%	2%
Distribution	42 years	1% - 13%	2%
Communication	19 years	1% - 13%	5%
Administration and service	15 years	1% - 20%	8%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software and other intangible assets range from 9% to 11%.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no ARO has been recorded.

Goodwill

Goodwill represents the cost of acquired local distribution companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Per Accounting Standards Update (ASU) 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment, issued by the Financial Accounting Standards Board (FASB) in September 2011, the Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

For the year ended December 31, 2012, based on the qualitative assessment performed, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 2012.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques, and may use more than one. Techniques used to determine fair value include, but are not limited to, the use of recent third party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2012, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the Consolidated Balance Sheets. Deferred debt costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's discounted cash flow hedges, and the change in fair value on the 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 allocated hedged debt. Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 12 – Fair Value of Financial Instruments and Risk Management.

Short-term investments have an original maturity of three months or less and are generally classified as held-to-maturity. However, the Company may classify pools of short-term investments as held-for-trading where there is no intention to hold a pool of assets to maturity. Documentation of the short-term investment classification is made on inception. As at December 31, 2012 and 2011, all short-term investments were classified as held-to-maturity.

The Company's long-term investment in Province of Ontario Floating-Rate Notes, which is held as an alternate form of liquidity to supplement the bank credit facilities, is classified as held-for-trading and is measured at fair value.

All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized in its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statement of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. Additionally, the Company enters into derivative agreements that are economic hedges that either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2012.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The net asset for an overfunded plan is classified as a long-term asset in the Consolidated Balance Sheets. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan. The regulatory asset for the net underfunded projected benefit obligation for the pension plan, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension regulatory assets are remeasured at the end of each year based on the current status of the pension plan.

In accordance with the OEB's rate orders, pension costs are recorded on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs are also calculated on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year.

All future pension benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Post-retirement and post-employment benefits

Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded on transition to US GAAP and at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates 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 are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Multiemployer Pension Plan

Employees of Hydro One Brampton Networks participate in the Ontario Municipal Employees Retirement System Fund (OMERS), a multiemployer, contributory, defined benefit public sector pension fund. OMERS provides retirement pension payments based on members' length of service and salary. Both participating employers and members are required to make plan contributions. The OMERS plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated by member entity. OMERS is registered with the Financial Services Commission of Ontario under Registration #0345983.

The OMERS plan is accounted for as a defined contribution plan by Hydro One because it is not practicable to determine the present value of the Company's obligation, the fair value of plan assets or the related current service cost applicable to Hydro One Brampton Networks' employees. Hydro One recognizes its contributions to the OMERS plan as pension expense, with a portion being capitalized. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

At December 31, 2011, OMERS had approximately 419,000 members, with approximately 277 members being current employees of Hydro One Brampton Networks.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgements regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgements about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

AROs are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional AROs are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an ARO, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company’s transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have AROs, 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 ARO currently exists for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable ARO exists. In such a case, an ARO would be recorded at that time.

The Company’s AROs recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In September 2011, the FASB issued ASU 2011-09, Disclosures About an Employer’s Participation in a Multiemployer Benefit Plan. This ASU requires an employer to provide quantitative and qualitative disclosures about its participation in significant multiemployer plans that offer pension, post-retirement and post-employment benefits. The ASU’s objective is to enhance the transparency of disclosures about the significant multiemployer plans in which an employer participates, the level of the employer’s participation in those plans, the financial health of the plans, and the nature of the employer’s commitments to the plans. An employer that is not able to provide some of the quantitative information required by this ASU must disclose what information has been omitted and why it could not obtain the information. This ASU does not change the recognition and measurement guidance for an employer’s participation in a multiemployer plan. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Company’s Consolidated Financial Statements.

In September 2011, the FASB issued ASU 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment. This ASU is intended to reduce the cost and complexity of the annual goodwill impairment test by providing entities an option to perform a qualitative assessment to determine whether further impairment testing is necessary. An entity has the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step test. If an entity believes, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount, the quantitative impairment test is required. Otherwise, no further testing is required. An entity can choose to perform the qualitative assessment on none, some or all of its reporting units. Moreover, an entity can bypass the qualitative assessment for any reporting unit in any period and proceed directly to step one of the impairment test, and then resume performing the qualitative assessment in any subsequent period. The adoption of this ASU did not have a significant impact on the Company’s Consolidated Financial Statements.

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income to clarify that an entity has the option to present the total of comprehensive income, the components of net income, and the components of OCI either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of OCI along with a total for OCI, and a total amount for comprehensive income. This update eliminates the option to present the components of OCI as part of the statement of changes in shareholder's equity. The amendments in this ASU do not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. Hydro One has elected to present OCI and net income in a single continuous Consolidated Statement of Operations and Comprehensive Income.

In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs. This ASU is the result of joint efforts by the FASB and the International Accounting Standards Board to develop common, converged fair value guidance on how to measure fair value and on what disclosures to provide about fair value measurements. This ASU is largely consistent with existing US GAAP fair value measurement principles under Accounting Standards Codification 820. However, this ASU expands the existing disclosure requirements for fair value measurements, particularly of Level 3 inputs, and requires categorization by level of the fair value hierarchy for items that are not measured at fair value on the Consolidated Balance Sheets but for which the fair value is required to be disclosed. Required disclosures have been included in Note 12 – Fair Value of Financial Instruments and Risk Management. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an entity to disclose both gross and net information about financial instruments and transactions eligible for offset on the Consolidated Balance Sheets as well as financial instruments and transactions executed under a master netting or similar arrangement. The ASU was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on an entity's financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this ASU only requires enhanced disclosures, the adoption of this ASU is not anticipated to have a significant impact on the Company's Consolidated Financial Statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of dollars)	**2012**	**2011**
Depreciation of property, plant and equipment	522	485
Amortization of intangible assets	48	45
Asset removal costs	70	66
Amortization of regulatory assets	19	20
	659	616

5. FINANCING CHARGES

Year ended December 31 (millions of dollars)	**2012**	**2011**
Interest on long-term debt	421	412
Other	12	5
Less: Interest capitalized on construction and development in progress	(59)	(58)
Gain on interest-rate swap agreements	(12)	(12)
Interest earned on investments	(4)	(3)
	358	344

6. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The major components of income tax expense are as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Current provision for PILs	130	162
Deferred recovery of PILs	(9)	(12)
Provision for PILs	121	150

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 the effective tax rates is provided as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Income before provision for PILs	866	791
Canadian Federal and Ontario statutory income tax rate	26.50%	28.25%
Provision for PILs at statutory rate	230	223
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(42)	(34)
Pension contributions in excess of pension expense	(23)	(17)
Interest capitalized for accounting but deducted for tax purposes	(15)	(16)
Overheads capitalized for accounting but deducted for tax purposes	(14)	(12)
Non-refundable investment tax credits	(8)	-
Environmental expenditures	(5)	(4)
Post-retirement and post-employment benefit expense in excess of cash payments	-	5
Other	(3)	3
Net temporary differences	(110)	(75)
Net permanent differences	1	2
Total provision for PILs	121	150
Current provision for PILs	130	162
Deferred recovery of PILs	(9)	(12)
Total provision for PILs	121	150
Effective income tax rate	13.96%	18.96%

The current provision for PILs of $130 million represents the amount paid or payable to the OEFC with respect to current year income. The outstanding balance due to the OEFC at December 31, 2012 was $10 million (2011 – $85 million).

The total provision for PILs includes deferred recovery of PILs of $9 million that is not included in the rate-setting process, using the balance sheet liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. At December 31, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of dollars)	**2012**	**2011**
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	3	6
Post-retirement and post-employment benefits expense in excess of cash payments	7	5
Environmental expenditures	4	5
Other	-	1
Total deferred income tax assets	14	17
Less: current portion	-	-
	14	17

December 31 (millions of dollars)	**2012**	**2011**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,344)	(1,106)
Post-retirement and post-employment benefits expense in excess of cash payments	519	356
Environmental expenditures	62	61
Regulatory amounts receivable that are not recognized for tax purposes	(147)	(36)
Goodwill	(19)	(18)
Other	3	4
Total deferred income tax liabilities	(926)	(739)
Less: current portion	18	19
	(944)	(758)

During 2012, the deferred tax liability increased by $60 million as a result of the change in the rate applicable to future taxes. At December 31, 2012, unused tax losses carried forward were less than $1 million (2011 – less than $1 million).

7. ACCOUNTS RECEIVABLE

December 31 (millions of dollars)	**2012**	**2011**
Accounts receivable – billed	224	235
Accounts receivable – unbilled	644	588
Accounts receivable, gross	868	823
Allowance for doubtful accounts	(23)	(18)
Accounts receivable, net	845	805

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2012 and 2011.

Year ended December 31 (millions of dollars)	**2012**	**2011**
Allowance for doubtful accounts – January 1	(18)	(25)
Write-offs	17	30
Additions to allowance for doubtful accounts	(22)	(23)
Allowance for doubtful accounts – December 31	(23)	(18)

8. PROPERTY, PLANT AND EQUIPMENT

December 31 (millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
2012				
Transmission	11,840	3,990	641	8,491
Distribution	8,005	2,879	234	5,360
Communication	1,024	516	57	565
Administration and Service	1,314	668	123	769
Easements	614	92	-	522
	22,797	8,145	1,055	15,707
2011				
Transmission	10,906	3,810	1,079	8,175
Distribution	7,596	2,706	253	5,143
Communication	919	468	43	494
Administration and Service	1,232	607	61	686
Easements	493	88	-	405
	21,146	7,679	1,436	14,903

Financing charges capitalized on property, plant and equipment under construction were $56 million in 2012 (2011 – $57 million).

9. INTANGIBLE ASSETS

December 31 (millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2012				
Computer applications software	451	301	116	266
Other	5	4	-	1
	456	305	116	267
2011				
Computer applications software	427	254	49	222
Other	5	3	-	2
	432	257	49	224

Financing charges capitalized on intangible assets under development were $3 million in 2012 (2011 – $1 million). The estimated annual amortization expense for intangible assets for each of the next five years is $42 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (millions of dollars)	**2012**	**2011**
Regulatory assets:		
Pension benefit regulatory asset	1,515	779
Deferred income tax regulatory asset	954	763
Post-retirement and post-employment benefits	320	123
Environmental	249	257
Pension cost variance	61	42
Rider 2	10	11
Long-term project development costs	5	5
Other	13	10
Total regulatory assets	3,127	1,990
Less: current portion	29	24
	3,098	1,966
Regulatory liabilities:		
External revenue variance	61	39
Retail settlement variance accounts	54	39
Rider 8	45	41
Deferred income tax regulatory liability	16	25
PST savings deferral	13	8
Rider 3	9	9
Rural and remote rate protection variance	6	8
Hydro One Brampton Networks rider	-	2
Other	17	23
Total regulatory liabilities	221	194
Less: current portion	40	25
	181	169

Pension Benefit Regulatory Asset

The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $736 million (2011 – higher by $482 million).

Deferred Income Tax Regulatory Asset and Liability

Deferred 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 that correspond to deferred 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 established for taxes to be recovered through future rates. As a result, the 2012 provision for PILs would have been higher by approximately $136 million (2011 – $70 million), including the impact of a change in enacted tax rates.

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $197 million (2011 – higher by $30 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 15 – Environmental Liabilities). Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2012, this regulatory asset decreased by $3 million (2011 – $55 million) to reflect related changes in the Company's PCB liability, and increased by $2 million (2011 – $5 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2012 operation, maintenance and administration expenses would have been lower by $1 million (2011 – $50 million). In addition, 2012 amortization expense would have been lower by $18 million (2011 – $16 million), and 2012 financing charges would have been higher by $11 million (2011 – $14 million).

Pension Cost Variance

A pension cost variance account was established for each of Hydro One Networks' Transmission and Distribution businesses to track the difference between the actual pension expense incurred and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension costs paid as compared to OEB-approved amounts. In December 2010, 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, 2012 revenue would have been lower by $18 million (2011 – $14 million).

Rider 2

In April 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 Rider 2 regulatory asset includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

Long-Term Project Development Costs

In May 2009, the OEB approved the creation of a deferral account to record Hydro One Networks' costs of preliminary work to advance certain transmission projects identified in the Company's 2009 and 2010 transmission rate applications. In March 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 2009 request from the Ministry of Energy and Infrastructure. In December 2010, the OEB approved the recovery of 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, 2011 operation, maintenance and administration expenses would have been lower by $2 million.

External Revenue Variance

In May 2009, 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 taken into account in structuring the Company's revenue requirement and as such, the OEB requested the establishment of new variance accounts to capture any difference between the approved forecasted external revenue amounts used in establishing the revenue requirement and actual external revenues. The external revenue variance account balance reflects the excess of actual external revenue compared to the OEB-approved forecasted amounts. In December 2010, the OEB approved the disposition of the December 31, 2009 balance, including accrued interest, to be disposed over a one-year period from January 1, 2011 to December 31, 2011.

Retail Settlement Variance Accounts (RSVAs)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In April 2010, the OEB approved the disposition of the total RSVA balance accumulated from May 2008 to December 2009, including accrued interest, to be disposed over a 20-month period from May 1, 2010 to December 31, 2011. Hydro One has continued to accumulate a net liability in its RSVA accounts since December 31, 2009.

Rider 8

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administrative expenses or capital expenditures for past revenue requirements approved during a full cost of service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administrative expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable and calculations for tracking and refund were requested by the OEB. For the Hydro One Networks Transmission revenue requirement, PST was included between July 1, 2010 and December 31, 2010 and recorded in a deferral account per direction from the OEB. For the Hydro One Networks Distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2012 and recorded in a deferral account per direction from the OEB.

Rider 3

In December 2008, the OEB approved certain distribution-related deferral account balances sought by Hydro One, including RSVA amounts, deferred tax changes, OEB costs and smart meters. The OEB approved the disposition of the Rider 3 balance accumulated up to April 2008, including accrued interest, to be disposed over a 27-month period from February 1, 2009 to April 30, 2011.

Rural and Remote Rate Protection Variance (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. The OEB has 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.

Hydro One Brampton Networks Rider

In April 2010, the OEB issued a decision regarding the 2010 distribution rates of Hydro One Brampton Networks. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVAs, sought by Hydro One Brampton Networks in its application. The OEB ordered that the approved balances be aggregated into a single regulatory account and disposed of through a rate rider over a two-year period from May 1, 2010 to April 30, 2012.

11. DEBT AND CREDIT AGREEMENTS

Short-Term Notes

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program with a maximum amount of $1,000 million. These short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. Hydro One had no commercial paper borrowings outstanding as at December 31, 2012 and 2011.

The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving standby credit facility with a syndicate of banks and a long-term investment in Province of Ontario Floating-Rate Notes with a fair value of $251 million at December 31, 2012.

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under this program is $3,000 million. At December 31, 2012, $1,515 million remained available until September 2013.

The following table presents the outstanding long-term debt at December 31, 2012 and 2011:

December 31 (millions of dollars)	**2012**	**2011**
5.77% Series 3 notes due 2012	-	600
5.00% Series 15 notes due 2013	600	600
3.13% Series 19 notes due 2014[1]	750	750
2.95% Series 21 notes due 2015[1]	500	500
Floating-rate Series 22 notes due 2015[2]	50	50
4.64% Series 10 notes due 2016	450	450
Floating-rate Series 27 notes due 2016[2]	50	-
5.18% Series 13 notes due 2017	600	600
4.40% Series 20 notes due 2020	300	300
3.20% Series 25 notes due 2022	600	-
7.35% debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
5.00% Series 11 notes due 2046	325	325
4.00% Series 24 notes due 2051	225	100
3.79% Series 26 notes due 2062	310	-
	8,460	7,975
Add: Unrealized marked-to-market loss[1]	19	33
Less: Long-term debt payable within one year	(600)	(600)
Long-term debt	7,879	7,408

[1] The unrealized marked-to-market loss relates to $500 million of the Series 19 notes due 2014, and $250 million of the Series 21 notes due 2015. The unrealized marked-to-market loss is offset by a $19 million (2011 – $33 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 12 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

[2] The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

In 2012, Hydro One issued $1,085 million of long-term debt under the MTN Program, consisting of $300 million issued in the first quarter, $425 million issued in the second quarter, $310 million issued in the third quarter, and $50 million issued in the fourth quarter of 2012. In September 2012, the Company also redeemed the $600 million MTN Series 3 notes.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 12 – Fair Value of Financial Instruments and Risk Management.

Credit Agreements

Hydro One has a $1,250 million committed and unused revolving standby credit facility with a syndicate of banks, maturing in June 2017. 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 may use the credit facility for general corporate purposes, including meeting short-term funding requirements. The obligation of each lender to make any credit extension to the Company under its credit facility is subject to various conditions including, among other things, that no event of default has occurred or would result from such credit extension.

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2012 and 2011, the Company's carrying amounts of accounts receivable, due from related parties, short-term investments, bank indebtedness, accounts payable, accrued liabilities, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2012 and 2011 are as follows:

December 31 (millions of dollars)	2012 Carrying Value	2012 Fair Value	2011 Carrying Value	2011 Fair Value
Long-term debt				
$500 million of MTN Series 19 notes[1]	512	512	521	521
$250 million of MTN Series 21 notes[2]	257	257	262	262
Other notes and debentures[3]	7,710	9,188	7,225	8,615
	8,479	9,957	8,008	9,398

[1] The fair value of $500 million of the MTN Series 19 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of $250 million of the MTN Series 21 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[3] The fair value of other notes and debentures, and the portions of the MTN Series 19 notes and the MTN Series 21 notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

At December 31, 2012, the Company had interest-rate swaps totaling $750 million (2011 – $750 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Company's fair value hedge exposure was equal to about 9% (2011 – 9%) of its total long-term debt of $8,479 million (2011 – $8,008 million). At December 31, 2102, the Company had the following interest-rate swaps designated as fair value hedges:

(a) two $250 million fixed-to-floating interest-rate swap agreements to convert $500 million of the $750 million MTN Series 19 notes maturing November 19, 2014 into three-month variable rate debt; and

(b) two $125 million fixed-to-floating interest-rate swap agreements to convert $250 million of the $500 million MTN Series 21 notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2012, the Company also had interest-rate swaps with a total notional value of $900 million classified as undesignated contracts. The undesignated contracts consist of the following interest-rate swaps:

(c) three $250 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company pays on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2012 to December 11, 2013, from February 21, 2012 to February 19, 2013, and from February 19, 2013 to February 19, 2014, respectively;

(d) two $50 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 24, 2012 to January 24, 2013, and from January 24, 2013 to January 24, 2014; and

(e) a $50 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 27 notes from March 4, 2013 to December 3, 2013.

At December 31, 2012 and 2011, the Company's carrying amounts of derivative instruments were representative of fair value.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2012 and 2011 is as follows:

December 31, 2012 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Short-term investments	195	195	-	195	-
Long-term investment	251	251	-	251	-
Derivative instruments					
Fair value hedges – interest-rate swaps	19	19	-	19	-
	465	465	-	465	-
Liabilities:					
Bank indebtedness	42	42	42	-	-
Long-term debt	8,479	9,957	-	9,957	-
	8,521	9,999	42	9,957	-

December 31, 2011 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Short-term investments	228	228	-	228	-
Long-term investment	250	250	-	250	-
Derivative instruments					
Fair value hedges – interest-rate swaps	33	33	-	33	-
Undesignated contracts – interest-rate swaps	1	1	-	1	-
	512	512	-	512	-
Liabilities:					
Bank indebtedness	39	39	39	-	-
Long-term debt	8,008	9,398	-	9,398	-
	8,047	9,437	39	9,398	-

The short-term investments represent investments with an original maturity of three months or less. The fair value of the short-term investments is determined using inputs other than quoted prices that are observable for the assets. The Company obtains quotes for the fair value of the short-term investments from an independent third party.

The long-term investment represents the Province of Ontario Floating-Rate Notes. The fair value of the long-term investment is determined using inputs other than quoted prices that are observable for the asset, with unrecognized gains or losses recognized in financing charges. The Company obtains quotes from an independent third party for the fair value of the long-term investment, who uses the market price of similar securities adjusted for changes in observable inputs such as maturity dates and interest rates.

The fair value of the derivative instruments is determined using other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2012 and 2011.

See Note 14 – Pension and Post-Retirement and Post-Employment Benefits for further information regarding the fair value and related valuation techniques for pension plan assets.

Risk Management

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 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 its risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's transmission and distribution businesses is derived using a formulaic approach that 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 the Transmission Business' results of operations by approximately $18 million (2011 – $18 million) and Hydro One Networks' Distribution Business' results of operations by approximately $10 million (2011 – $10 million).

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, the Company may utilize interest-rate derivative instruments to lock in interest rate levels in anticipation of future financing. Hydro One may also 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. Such arrangements are typically designated as cash flow hedges. No cash flow hedge agreements were outstanding as at December 31, 2012 or 2011.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's results of operations for the years ended December 31, 2012 or 2011.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest rate swaps for the years ended December 31, 2012 and 2011 are included in financing charges as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Unrealized loss (gain) on hedged debt	(14)	25
Unrealized loss (gain) on fair value interest-rate swaps	14	(25)
Net unrealized loss (gain)	-	-

At December 31, 2012, Hydro One had $750 million (2011 – $750 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $19 million (2011 – $33 million). During the years ended December 31, 2012 and 2011, there was no significant impact on the results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2012 and 2011, 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. At December 31, 2012 and 2011, there was no significant accounts receivable balance due from any single customer.

At December 31, 2012, the Company's provision for bad debts was $23 million (2011 – $18 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2012, approximately 3% of the Company's accounts receivable were aged more than 60 days (2011 – 3%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties 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 counterparties. In addition to payment netting language in master agreements, the Company establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. The Company would only offset the positive market values against negative values with the same counterparty where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with the Company as specified in each agreement. The Company monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2012, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $22 million (2011 – $36 million). At December 31, 2012, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties. The credit exposure of each of the four counterparties accounted for more than 10% of the total credit exposure.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, the revolving standby credit facility, and by holding 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 in June 2017 and the Province of Ontario Floating-Rate Notes with a fair value of $251 million. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2012, accounts payable and accrued liabilities in the amount of $722 million are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2012, Hydro One had issued long-term debt in the notional amount of $8,460 million (2011 – $7,975 million). Long-term debt maturing during the next year is $600 million (2011 – $600 million). Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $410 million (2011 – $408 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 Long-term Debt *(millions of dollars)*	Interest Payments[1] *(millions of dollars)*	Weighted Average Interest Rate[1] *(%)*
1 year	600	410	5.0
2 years	750	379	3.1
3 years	550	356	2.8
4 years	500	331	4.3
5 years	600	320	5.2
	3,000	1,796	4.1
6 – 10 years	900	1,403	3.6
Over 10 years	4,560	4,138	5.6
	8,460	7,337	4.9

[1] Interest payments and weighted average interest rates beyond 1 year exclude the impact of the $50 million floating-rate Series 22 notes due 2015 and the $50 million floating-rate Series 27 notes due 2016.

13. 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, preferred shares, long-term debt, and cash and cash equivalents. At December 31, 2012 and 2011, the Company's capital structure was as follows:

December 31 (millions of dollars)	**2012**	**2011**
Long-term debt payable within one year	600	600
Less: Cash and cash equivalents	195	228
	405	372
Long-term debt	7,879	7,408
Preferred shares	323	323
Common shares	3,314	3,314
Retained earnings	3,202	2,827
	6,516	6,141
Total capital	15,123	14,244

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, 2012 and 2011, Hydro One was in compliance with all of these covenants and limitations.

14. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks. Employees of Hydro One Brampton Networks participate in the OMERS plan, a multiemployer public sector pension fund. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

The OMERS Plan

Hydro One contributions to the OMERS plan for the year ended December 31, 2012 were $2 million (2011 – $1 million). Company contributions payable at December 31, 2012 and included in accrued liabilities on the Consolidated Balance Sheets were $0.2 million (2011 – $0.2 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS plan, as indicated in OMERS's most recently available annual report for the year ended December 31, 2011.

At December 31, 2011, the OMERS plan was 88.7% funded, with an unfunded liability of $7,290 million. This unfunded liability will likely result in future payments by participating employers and members. Hydro One future contributions could be increased substantially if other entities withdraw from the plan.

Pension Plan, Post-Retirement and Post-Employment Plans

The 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-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Company and employees' contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2012 of $163 million (2011 – $152 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2012 pensionable earnings. Estimated annual Pension Plan contributions for 2013 are $162 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. For the year ended December 31, 2012, the measurement date for the Plans was December 31.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	5,461	4,996	1,206	1,178
Current service cost	123	108	29	30
Interest cost	285	286	63	68
Reciprocal transfers	1	4	-	-
Benefits paid	(291)	(289)	(42)	(42)
Net actuarial loss (gain)	928	356	203	(28)
Projected benefit obligation, end of year	6,507	5,461	1,459	1,206
Change in plan assets				
Fair value of plan assets, beginning of year	4,682	4,699	-	-
Actual return on plan assets	425	102	-	-
Reciprocal transfers	1	4	-	-
Benefits paid	(291)	(289)	-	-
Employer's contributions	163	153	-	-
Employees' contributions	27	27	-	-
Administrative expenses	(15)	(14)	-	-
Fair value of plan assets, end of year	4,992	4,682	-	-
Unfunded status	1,515	779	1,459	1,206

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets within the following line items:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Accrued liabilities	-	-	43	43
Pension benefit liability	1,515	779	-	-
Post-retirement and post-employment benefit liability	-	-	1,416	1,163
Unfunded status	1,515	779	1,459	1,206

The funded/unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan.

December 31 (millions of dollars)	**2012**	**2011**
PBO	6,507	5,461
ABO	6,074	5,038
Fair value of plan assets	4,992	4,682

On an ABO basis, the plans were funded at 82% at December 31, 2012 (2011 – 93%). On a PBO basis, the plans were funded at 77% at December 31, 2012 (2011 – 86%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2012 and 2011 for all plans:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Current service cost, net of employee contributions	96	81	30	30
Interest cost	285	286	63	67
Expected return on plan assets net of expenses	(289)	(291)	-	-
Actuarial loss amortization	112	68	8	7
Prior service cost amortization	3	4	3	4
Net Periodic Benefit Cost	207	148	104	108
Charged to results of operations[1]	76	93	48	61

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the year ended December 31, 2012, pension costs of $163 million (2011 – $153 million) were attributed to labour, of which $76 million (2011 – $93 million) was charged to operations and $87 million (2011 – $60 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

Assumptions

The measurement of the obligations of the Plans and costs of providing benefits under Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed income securities.

The following weighted average assumptions were used to determine the benefit obligations and benefit expense at December 31, 2012 and 2011. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2012**	**2011**	**2012**	**2011**
Significant assumptions:				
For net periodic benefit cost, year ended December 31:				
Weighted average expected rate of return on plan assets	6.25%	6.25%	-	-
Weighted average discount rate	5.25%	5.75%	5.25%	5.75%
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%
Average remaining service life of employees *(years)*	11	11	11	11
Rate of increase in health care cost trends[1]	-	-	4.41%	4.91%
For projected benefit obligation, at December 31:				
Weighted average discount rate	4.25%	5.25%	4.25%	5.25%
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 trends[2]	-	-	4.39%	4.41%

[1] 7.03% per annum in 2012, grading down to 4.41% per annum in and after 2031 (2011 – 7.56% in 2011, grading down to 4.91% per annum in and after 2029)

[2] 6.91% per annum in 2013, grading down to 4.39% per annum in and after 2031 (2011 – 7.03% in 2012, grading down to 4.41% per annum in and after 2031)

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third party bond yield curve corresponding to each duration. The yield curve is based on AA long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of 1% change in health care cost trends on the post-retirement and post-employment benefits is as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Effect of 1% increase in health care cost trends on:		
Projected benefit obligation at December 31	246	174
Service cost and interest cost	17	20
Effect of 1% decrease in health care cost trends on:		
Projected benefit obligation at December 31	(191)	(138)
Service cost and interest cost	(13)	(14)

Estimated Future Benefit Payments

At December 31, 2012, estimated future benefit payments by the Company to Plan participants were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2013	299	51
2014	306	54
2015	313	57
2016	318	61
2017	324	64
2018 through to 2022	1,690	374
Total estimated future benefit payments through to 2022	3,250	661

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Actuarial loss (gain) for the year	807	558	203	(27)
Actuarial loss amortization	(112)	(68)	(8)	(7)
Prior service cost amortization	(3)	(4)	(3)	(3)
	692	486	192	(37)

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2012 and 2011:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Prior service cost	5	7	5	7
Actuarial loss	1,510	772	315	116
	1,515	779	320	123

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	**2011**	**2012**	**2011**
Prior service cost	2	3	3	3
Actuarial loss	175	112	17	4
	177	115	20	7

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Investment-Pension Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2012, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

December 31, 2012	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	64.1
Debt securities	35.0	35.8
Other [1]	5.0	0.1
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2012, the Pension Plan held $20 million of Hydro One corporate bonds (2011 – $27 million) and $243 million of debt securities of the Province (2011 – $214 million).

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2012 and 2011. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2012 and 2011, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with financial institutions rated at least "AA" by S&P or "Aa2" by Moody's Investors Service Inc. and also by utilizing exposure limits to each counterparty. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following table presents the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2012 and 2011:

December 31, 2012 (millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	2	15	104	121
Cash and cash equivalents	125	-	-	125
Short-term securities	-	100	-	100
Real estate	-	-	2	2
Corporate shares – Canadian	920	-	-	920
Corporate shares – Foreign	2,077	-	-	2,077
Bonds and debentures – Canadian	-	1,643	-	1,643
Total fair value of plan assets[1]	3,124	1,758	106	4,988

[1] At December 31, 2012, the total fair value of Pension Plan assets excludes $16 million of interest and dividends receivable, $4 million relating to accruals for pending sales transactions and $8 million relating to accruals for pension administration expense.

December 31, 2011 (millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	3	15	165	183
Cash and cash equivalents	128	-	-	128
Short-term securities	-	38	-	38
Real estate	-	-	2	2
Corporate shares – Canadian	820	-	-	820
Corporate shares – Foreign	1,820	-	-	1,820
Bonds and debentures – Canadian	-	1,675	-	1,675
Bonds and debentures – Foreign	-	1	-	1
Total fair value of plan assets[1]	2,771	1,729	167	4,667

[1] At December 31, 2011, the total fair value of Pension Plan assets excludes $17 million of interest and dividends receivable, $8 million of receivables relating to pending sales transactions, and $10 million relating to accruals for pension administration expense.

See Note 12 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2012 and 2011. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 (millions of dollars)	**2012**	**2011**
Fair value, beginning of year	167	167
Realized and unrealized gains	5	18
Purchases	6	9
Sales and disbursements	(72)	(27)
Fair value, end of year	106	167

There have been no material transfers into or out of Level 3 of the fair value hierarchy.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. These sensitivity analyses resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled Funds

The pooled fund category mainly consists of private equity investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3 within pooled funds.

Cash Equivalents

Demand cash deposits held with banks and cash held by the investment managers are considered cash equivalents and are included in the fair value measurements hierarchy as Level 1.

Short-Term Securities

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities have been categorized as Level 2.

Real Estate

Real estate investments represent private equity investments in holding companies that invest in real estate properties. The investments in the holding companies are valued using net asset values reported by the fund manager. Real estate investments are categorized as Level 3.

Corporate Shares

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and Debentures

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

15. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Consolidated Balance Sheets at December 31, 2012 and 2011:

December 31 (millions of dollars)	PCB	LAR	Total
2012			
Environmental liabilities, January 1	199	58	257
Interest accretion	9	2	11
Expenditures	(8)	(10)	(18)
Revaluation adjustment	(3)	2	(1)
Environmental liabilities, December 31	197	52	249
Less: current portion	(13)	(9)	(22)
	184	43	227

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Environmental liabilities, January 1	251	58	309
Interest accretion	12	2	14
Expenditures	(9)	(7)	(16)
Revaluation adjustment	(55)	5	(50)
Environmental liabilities, December 31	199	58	257
Less: current portion	(13)	(9)	(22)
	186	49	235

The following table illustrates the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized in the Consolidated Balance Sheets after factoring in the discount rate:

December 31 (millions of dollars)	PCB	LAR	Total
2012			
Undiscounted environmental liabilities, December 31	233	54	287
Less: discounting accumulated liabilities to present value	(36)	(2)	(38)
Discounted environmental liabilities, December 31	197	52	249

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Undiscounted environmental liabilities, December 31	242	61	303
Less: discounting accumulated liabilities to present value	(43)	(3)	(46)
Discounted environmental liabilities, December 31	199	58	257

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2012 and in total thereafter are as follows: 2013 – $22 million; 2014 – $38 million; 2015 – $36 million; 2016 – $22 million; 2017 – $17 million; and thereafter – $152 million. At December 31, 2012, of the total estimated future environmental expenditures, $233 million relate to PCB (2011 – $242 million) and $54 million relate to LAR (2011 – $61 million).

Consistent with its accounting policy for environmental costs, Hydro One records a liability for the estimated mandatory 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.

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 of the 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, with respect to the PCB environmental liability, 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. The Company records a regulatory asset reflecting its expectation that future environmental costs will be recoverable in rates.

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

In September 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*. These regulations impose timelines for disposal of PCBs based on certain 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, with the exception of specifically exempted equipment. 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. 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 retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is approximately $233 million. These expenditures are expected to be incurred over the period from 2013 to 2025. As a result of its most recent cost estimate to comply with current PCB regulations, the Company recorded a revaluation adjustment to reduce the PCB environmental liability by approximately $3 million (2011 – $55 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is approximately $54 million. These expenditures are expected to be incurred over the period from 2013 to 2020. 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 recorded a revaluation adjustment to increase the LAR environmental liability by approximately $2 million (2011 – $5 million).

16. ASSET RETIREMENT OBLIGATIONS

AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO (with corresponding adjustments to property, plant and equipment), which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired and changes in federal, state or local regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

All factors used in estimating the Company's AROs 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. AROs 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 AROs, 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.

At December 31, 2012, Hydro One had recorded AROs of $15 million (2011 – $15 million), consisting of $7 million (2011 – $7 million) related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as $8 million (2011 – $8 million) related to the future decommissioning and removal of two of its switching stations.

The Company's liability for the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities is based on management's best estimate of the present value of the estimated future expenditures to comply with current regulations. In 2010, 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 amount of interest recorded is nominal and there have been no expenditures associated with these obligations to date.

In 2011, Hydro One recorded an ARO of $4 million related to the future decommissioning and removal of one of its switching stations, in addition to the ARO of $4 million recorded in a prior year related to the future decommissioning and removal of another switching station. The amount of interest recorded is nominal and there have been no expenditures associated with these obligations to date.

17. SHARE CAPITAL

Preferred Shares

The Company has 12,920,000 issued and outstanding 5.5% cumulative preferred shares with a redemption value of $25 per share or $323 million total value. The Company is authorized to issue an unlimited number of preferred shares.

The Company's preferred shares are entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which is payable on a quarterly basis. The preferred shares are not subject to mandatory redemption (except on liquidation) but are redeemable in certain circumstances. The shares are redeemable at the option of the Province at the redemption 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 the 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.

These preferred shares have conditions for their redemption that are outside the control of the Company because the Province can exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. Because the conditional redemption feature is outside the control of the Company, the preferred shares are classified outside of Shareholder's Equity on the Consolidated Balance Sheets. Management believes that it is not probable that the preferred shares will become redeemable. No adjustment to the carrying value of the preferred shares has been recognized at December 31, 2012. If it becomes probable in the future that the preferred shares will be redeemed, the redemption value would be adjusted.

Common Shares

The Company has 100,000 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

Common share 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 conditions, cash requirements, and other relevant factors, such as industry practice and shareholder expectations.

Earnings per Share

Earnings per share is calculated as net income for the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year.

18. DIVIDENDS

In 2012, preferred share dividends in the amount of $18 million (2011 – $18 million) and common share dividends in the amount of $352 million (2011 – $150 million) were declared.

19. RELATED PARTY TRANSACTIONS

Hydro One is owned by the Province. The OEFC, IESO, Ontario Power Authority (OPA), Ontario Power Generation Inc. (OPG) and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from the IESO, based on uniform transmission rates approved by the OEB. Transmission revenues include $1,474 million (2011 – $1,366 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues include $127 million (2011 – $127 million) related to this program. In 2012, Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenues include $28 million (2011 – $28 million) related to these services.

In 2012, Hydro One purchased power in the amount of $2,392 million (2011 – $2,401 million) from the IESO-administered electricity market; $10 million (2011 – $16 million) from OPG; and $7 million (2011 – $10 million) from the 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 transmitters. In 2012, Hydro One incurred $11 million (2011 – $11 million) in OEB fees.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2012, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $10 million (2011 – $7 million), primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were $2 million in 2012 (2011 – $2 million).

The OPA funds substantially all of the Company's Conservation and Demand Management (CDM) programs. The funding includes program costs, incentives, and management fees. In 2012, Hydro One received $39 million (2011 – $39 million) from the OPA related to the CDM programs.

The provision for PILs and payments in lieu of property taxes were paid or payable to the OEFC, and dividends were paid or payable to the Province.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are unsecured, interest free and settled in cash. At December 31, 2012, the Company held Province of Ontario Floating-Rate Notes with a fair value of $251 million (2011 – $250 million).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (millions of dollars)	**2012**	**2011**
Due from related parties	154	156
Due to related parties[1]	(257)	(342)
Long-term investment	251	250

[1] Included in due to related parties at December 31, 2012 are amounts owing to the IESO in respect of power purchases of $199 million (2011 – $209 million).

20. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of dollars)	2012	2011
Accounts receivable	(30)	(18)
Due from related parties	2	(32)
Materials and supplies	2	(4)
Other assets	(4)	(11)
Accounts payable	(14)	29
Accrued liabilities	10	98
Due to related parties	(85)	61
Accrued interest	10	1
Long-term accounts payable and other liabilities	13	-
Post-retirement and post-employment benefit liability	56	60
	(40)	184

Supplementary information:		
Net interest paid	411	410
Payments in lieu of corporate income taxes	197	80

21. 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.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, the Company anticipates having to pay more than the $1 million that it paid in 2012. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

22. COMMITMENTS

Agreement with Inergi LP (Inergi)

Effective March 1, 2002, 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. This agreement will 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 billings for these services have ranged between $93 million and $130 million per year and are subject to external benchmarking every three years to ensure Hydro One is receiving a defined, competitive and continuously improved price.

At December 31, 2012, the annual commitments under the Inergi agreement are as follows: 2013 – $136 million; 2014 – $130 million; 2015 – $21 million; 2016 and thereafter – nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2012, the Company provided prudential support to the IESO on behalf of Hydro One Networks and Hydro One Brampton Networks using parental guarantees of $325 million (2011 – $325 million), and on behalf of two distributors using guarantees of $0.7 million (2011 – $0.7 million). On April 27, 2012, Hydro One's highest credit rating declined from the "Aa" category to the "A" category. Based on the new credit rating category, the Company has provided letters of credit in the amount of $22 million to the IESO. The IESO could draw on these guarantees and/or letters of credit 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 letters of credit plus the nominal amount of the parental guarantees.

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 supplementary pension plan trustee is required to draw upon these 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 letters of credit. At December 31, 2012, Hydro One had letters of credit of $127 million (2011 – $124 million) outstanding relating to retirement compensation arrangements.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service related functions and storing telecommunication equipment. These leases have an average life of between one and five years with renewal options for periods ranging from one to 10 years included in some of the contracts. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions. There are no restrictions placed upon Hydro One by entering into these leases. Hydro One Networks and Hydro One Telecom are the principal entities concerned.

At December 31, 2012, the future minimum lease payments under non-cancellable operating leases were as follows:

December 31 (millions of dollars)	**2012**	**2011**
Within one year	10	8
After one year but not more than five years	29	26
More than five years	14	20
	53	54

During the year ended December 31, 2012, the Company made lease payments totaling $9 million (2011 – $6 million).

23. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing electricity 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
- Other, the operations of which primarily consist of those of the telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Operating segments for the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance at each of the segments. The Company evaluates segment performance based on income before financing charges and provision for PILs from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2 – Significant Accounting Policies). Segment information on the above basis is as follows:

Year ended December 31, 2012 (millions of dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment profit				
Revenues	1,482	4,184	62	5,728
Purchased power	-	2,774	-	2,774
Operation, maintenance and administration	402	608	61	1,071
Depreciation and amortization	320	329	10	659
Income (loss) before financing charges and provision for PILs	760	473	(9)	1,224
Financing charges				358
Income before provision for PILs				866
Capital expenditures	776	671	7	1,454

Year ended December 31, 2011 (millions of dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment profit				
Revenues	1,389	4,019	63	5,471
Purchased power	-	2,628	-	2,628
Operation, maintenance and administration	422	609	61	1,092
Depreciation and amortization	302	304	10	616
Income (loss) before financing charges and provision for PILs	665	478	(8)	1,135
Financing charges				344
Income before provision for PILs				791
Capital expenditures	810	628	9	1,447

December 31 (millions of dollars)	**2012**	**2011**
Total assets		
Transmission	11,586	10,589
Distribution	8,621	7,594
Other	604	653
	20,811	18,836

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

24. TRANSITION TO US GAAP

The adoption of US GAAP has been made on a retrospective basis with restatement of comparative information to reflect US GAAP requirements in effect at that time. The Company's transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to the Company's 2012 Consolidated Financial Statements.

Measurement and classification differences resulting from Hydro One's adoption of US GAAP are presented below. With respect to measurement and classification differences, the tables under the heading US GAAP Differences represent quantitative reconciliations of the Consolidated Balance Sheets and the Consolidated Statements of Changes in Shareholder's Equity, previously presented in accordance with Canadian GAAP, to the respective amounts and classifications under US GAAP, together with descriptions of the various significant measurement and classification differences arising from the adoption of US GAAP. Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholder's Equity reconciliations are presented as at January 1, 2011 and December 31, 2011, representing the commencement and ending dates of the comparative financial year to 2012. There were no measurement or classification differences resulting from Hydro One's adoption of US GAAP on the Consolidated Statements of Operations and Comprehensive Income.

Except as otherwise disclosed in this note, the change in basis of accounting from Canadian GAAP to US GAAP did not materially impact accounting policies or disclosures. Reference should be made to the previously filed Canadian GAAP Consolidated Financial Statements as at and for the year ended December 31, 2011 for additional information on Canadian GAAP accounting policies and practices.

The following table summarizes the increases (decreases) to total assets:

(millions of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total assets – Canadian GAAP		17,322	18,368
Deferred debt costs	A	32	32
Deferred pension asset	B	(460)	(466)
Regulatory assets	B	450	902
Total assets – US GAAP		17,344	18,836

The following table summarizes the increases (decreases) to total liabilities:

(millions of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total liabilities – Canadian GAAP		11,341	11,914
Long-term debt	A	5	9
Net unamortized debt premiums	A	27	23
Pension benefit liability	B	297	779
Post-retirement and post-employment benefit liability	B	153	123
Regulatory liabilities	B	(460)	(466)
Total liabilities – US GAAP		11,363	12,382

US GAAP Differences

The reconciliations of the January 1, 2011 and December 31, 2011 Consolidated Balance Sheets from Canadian GAAP to US GAAP are as follows:

January 1, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Cash		33	-	33
Short-term investments		139	-	139
Accounts receivable	F	911	(124)	787
Due from related parties	F	-	124	124
Regulatory assets		42	-	42
Materials and supplies		21	-	21
Deferred income tax assets		35	-	35
Derivative instruments	C	-	1	1
Other	C	8	(1)	7
		1,189	-	1,189
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		12,520	-	12,520
Construction in progress		1,402	-	1,402
Future use land, components and spares		139	-	139
		14,061	-	14,061
Other long-term assets:				
Regulatory assets	B	1,013	450	1,463
Deferred pension asset	B	460	(460)	-
Long-term investment		249	-	249
Intangible assets (net of accumulated amortization)		189	-	189
Goodwill		133	-	133
Deferred debt costs	A	-	32	32
Derivative instruments	C	-	7	7
Deferred income tax assets		19	-	19
Other	C	9	(7)	2
		2,072	22	2,094
Total assets		17,322	22	17,344

January 1, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Liabilities				
Current liabilities:				
Accounts payable and accrued charges	D, F	884	(884)	-
Accounts payable	D	-	125	125
Accrued liabilities	D	-	478	478
Due to related parties	F	-	281	281
Accrued interest		84	-	84
Regulatory liabilities		72	-	72
Long-term debt payable within one year		500	-	500
		1,540	-	1,540
Long-term debt	A	7,278	5	7,283
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	980	153	1,133
Deferred income tax liabilities		693	-	693
Pension benefit liability	B	-	297	297
Environmental liabilities		287	-	287
Regulatory liabilities	B	540	(460)	80
Net unamortized debt premiums	A	-	27	27
Asset retirement obligations		11	-	11
Long-term accounts payable and other liabilities		12	-	12
		2,523	17	2,540
Total liabilities		11,341	22	11,363
Preferred shares	E	-	323	323
Shareholder's equity				
Preferred shares	E	323	(323)	-
Common shares		3,314	-	3,314
Retained earnings		2,354	-	2,354
Accumulated other comprehensive loss		(10)	-	(10)
Total shareholder's equity		5,981	(323)	5,658
Total liabilities, preferred shares and shareholder's equity		17,322	22	17,344

December 31, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Short-term investments		228	-	228
Accounts receivable	F	961	(156)	805
Due from related parties	F	-	156	156
Regulatory assets		24	-	24
Materials and supplies		25	-	25
Deferred income tax assets		19	-	19
Derivative instruments	C	-	1	1
Other	C	20	(1)	19
		1,277	-	1,277
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		13,329	-	13,329
Construction in progress		1,436	-	1,436
Future use land, components and spares		138	-	138
		14,903	-	14,903
Other long-term assets:				
Regulatory assets	B	1,064	902	1,966
Deferred pension asset	B	466	(466)	-
Long-term investment		250	-	250
Intangible assets (net of accumulated amortization)		224	-	224
Goodwill		133	-	133
Deferred debt costs	A	-	32	32
Derivative instruments	C	-	33	33
Deferred income tax assets		17	-	17
Other	C	34	(33)	1
		2,188	468	2,656
Total assets		18,368	468	18,836

December 31, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Liabilities				
Current liabilities:				
Bank indebtedness		39	-	39
Accounts payable and accrued charges	D, F	1,071	(1,071)	-
Accounts payable	D	-	154	154
Accrued liabilities	D	-	575	575
Due to related parties	F	-	342	342
Accrued interest		85	-	85
Regulatory liabilities		25	-	25
Long-term debt payable within one year		600	-	600
		1,820	-	1,820
Long-term debt	A	7,399	9	7,408
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	1,040	123	1,163
Deferred income tax liabilities		758	-	758
Pension benefit liability	B	-	779	779
Environmental liabilities		235	-	235
Regulatory liabilities	B	635	(466)	169
Net unamortized debt premiums	A	-	23	23
Asset retirement obligations		15	-	15
Long-term accounts payable and other liabilities		12	-	12
		2,695	459	3,154
Total liabilities		11,914	468	12,382
Preferred shares	E	-	323	323
Shareholder's equity				
Preferred shares	E	323	(323)	-
Common shares		3,314	-	3,314
Retained earnings		2,827	-	2,827
Accumulated other comprehensive loss		(10)	-	(10)
Total shareholder's equity		6,454	(323)	6,131
Total liabilities, preferred shares and shareholder's equity		18,368	468	18,836

The adjustments to the January 1, 2011 and December 31, 2011 equity from Canadian GAAP to US GAAP are as follows:

January 1, 2011 (millions of dollars)	Common Shares	Preferred Shares	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Shareholder's Equity
Canadian GAAP	3,314	323	(10)	2,354	5,981
Other comprehensive income	-	-	-	-	-
Preferred shares reclassified outside shareholder's equity	-	(323)	-	-	(323)
US GAAP	3,314	-	(10)	2,354	5,658

December 31, 2011 *(millions of dollars)*	Common Shares	Preferred Shares	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Shareholder's Equity
Canadian GAAP	3,314	323	(10)	2,827	6,454
Other comprehensive income	-	-	-	-	-
Preferred shares reclassified outside shareholder's equity	-	(323)	-	-	(323)
US GAAP	3,314	-	(10)	2,827	6,131

Notes to the Transitional Adjustments

Under US GAAP, the Company (i) measures certain assets and liabilities differently than it had under Canadian GAAP (see details on each measurement change below); and (ii) discloses certain assets, liabilities and equity on different lines in the Consolidated Financial Statements than it had under Canadian GAAP (see details on each classification change below).

A. Debt Issuance Costs (classification change)

Under Canadian GAAP, costs of arranging debt financing, premiums and discounts were netted against long-term debt. Under US GAAP, costs of arranging debt financing are included in "Deferred debt costs" as part of "Other long-term assets", and net unamortized premiums are included in "Net unamortized debt premiums" as part of "Other long-term liabilities".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases:

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Deferred debt costs	32	32
Other long-term liabilities:		
Net unamortized debt premiums	27	23
Long-term debt	5	9

B. Pension, Post-Retirement and Post-Employment Benefits (measurement change)

Under Canadian GAAP, the Company disclosed, but was not required to recognize, the net unfunded status of pension, post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets. Under US GAAP, the Company recognized the unfunded status of pension, post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets with an offset to associated regulatory assets for the transitional fair value adjustments as the incremental obligations are expected to be recovered through future rates charged to customers. The deferred tax assets and liabilities arising on recognition of incremental pension, post-retirement and post-employment benefit obligations and the associated regulatory assets offset each other, with no material impact on the Consolidated Statements of Operations and Comprehensive Income. In the absence of regulatory accounting, the related tax impact on the opening transitional adjustments would result in the recognition of deferred tax assets of $113 million on January 1, 2011 and $224 million on December 31, 2011.

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Deferred pension asset	(460)	(466)
Regulatory assets[1]	450	902
Other long-term liabilities:		
Pension benefit liability	297	779
Post-retirement and post-employment benefit liability	153	123
Regulatory liabilities[2]	(460)	(466)

[1] Represents offsetting regulatory assets for incremental obligations for pension and non-pension obligations of $297 million and $153 million on January 1, 2011, and $779 million and $123 million on December 31, 2011, respectively.

[2] Represents write-off of deferred pension asset regulatory liability under Canadian GAAP.

C. Derivative Instruments (classification change)

Under Canadian GAAP, the Company classified its derivative instruments in designated hedging relationships and in economic hedging relationships under the category of "Other assets" on the Consolidated Balance Sheets. Under US GAAP, the Company has included these balances in "Derivative instruments".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Current assets:		
Derivative instruments	1	1
Other	(1)	(1)
Other long-term assets:		
Derivative instruments	7	33
Other	(7)	(33)

D. Accounts Payable (classification change)

Under Canadian GAAP, trade and non-trade payables were disclosed as "Accounts payable and accrued charges". Under US GAAP, trade payables are recognized in "Accounts payable" and non-trade payables are recognized in "Accrued liabilities".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Current liabilities:		
Accounts payable	125	154
Accrued liabilities	478	575
Accounts payable and accrued charges	(603)	(729)

E. Preferred Shares (classification change)

Under Canadian GAAP, Hydro One's preferred shares were classified as equity, and preferred dividends were deducted from retained earnings and accrued as declared. Under US GAAP, the preferred shares are classified outside shareholder's equity because of conditional redemption features in the preferred share agreement. Under US GAAP, the preferred dividends continue to be deducted from retained earnings and accrued as declared (see Note 17 – Share Capital).

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Preferred shares	323	323
Shareholder's equity:		
Preferred shares	(323)	(323)

F. Related Party Balances (classification change)

Under Canadian GAAP, receivables from related parties and payables to related parties were disclosed as "Accounts receivable" and "Accounts payable and accrued charges", respectively. Under US GAAP, receivables from related parties are recognized in "Due from related parties" and payables to related parties are recognized in "Due to related parties".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Current assets:		
Due from related parties	124	156
Accounts receivable	(124)	(156)
Current liabilities:		
Due to related parties	281	342
Accounts payable and accrued charges	(281)	(342)

25. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2012 Consolidated Financial Statements.

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Statements of Operations Data *Year ended December 31 (millions of dollars)*	**2012**[1]	**2011**[1]	**2010**[2]	**2009**[2]	**2008**[2]
Revenues					
Distribution	4,184	4,019	3,754	3,534	3,334
Transmission	1,482	1,389	1,307	1,147	1,212
Other	62	63	63	63	51
	5,728	5,471	5,124	4,744	4,597
Costs					
Purchased power	2,774	2,628	2,474	2,326	2,181
Operation, maintenance and administration	1,071	1,092	1,078	1,057	965
Depreciation and amortization	659	616	583	537	548
	4,504	4,336	4,135	3,920	3,694
Income before financing charges and provision for payments in lieu of corporate income taxes	1,224	1,135	989	824	903
Financing charges	358	344	342	308	292
Income before provision for payments in lieu of corporate income taxes	866	791	647	516	611
Provision for payments in lieu of corporate income taxes	121	150	56	46	113
Net income	745	641	591	470	498
Basic and fully diluted earnings per common share *(dollars)*	7,280	6,228	5,727	4,528	4,797
Dividends per common share declared *(dollars)*	3,523	1,500	100	1,700	2,410

Balance Sheets Data *December 31 (millions of dollars)*	**2012**[1]	**2011**[1]	**2010**[1]	**2009**[2]	**2008**[2]
Assets					
Distribution	8,621	7,594	6,915	6,481	5,873
Transmission	11,586	10,589	9,820	8,993	7,877
Other	604	653	609	161	128
Total Assets	20,811	18,836	17,344	15,635	13,878
Liabilities					
Current liabilities (including current portion of long-term debt)	1,756	1,820	1,540	1,655	1,300
Long-term debt	7,879	7,408	7,283	6,281	5,733
Other long-term liabilities	4,346	3,154	2,540	2,281	1,721
Preferred shares	323	323	323	-	-
Shareholder's equity					
Preferred shares	-	-	-	323	323
Common shares	3,314	3,314	3,314	3,314	3,314
Retained earnings	3,202	2,827	2,354	1,791	1,497
Accumulated other comprehensive income	(9)	(10)	(10)	(10)	(10)
Total liabilities, preferred shares and shareholder's equity	20,811	18,836	17,344	15,635	13,878

[1] Based on US GAAP

[2] Based on Canadian GAAP

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS (continued)

Other Financial Data *Year ended December 31*	**2012**	**2011**	**2010**	**2009**	**2008**
Capital expenditures *(millions of dollars)*					
Distribution	671	628	629	643	570
Transmission	776	810	936	918	704
Other	7	9	5	5	10
Total capital expenditures	1,454	1,447	1,570	1,566	1,284
Ratios					
Net asset coverage on long-term debt ratio[1]	1.81	1.81	1.77	1.79	1.84
Earnings coverage ratio[2]	2.83	2.71	2.39	2.15	2.63
Operating statistics					
Transmission					
Units transmitted *(TWh)*[3]	141.3	141.5	142.2	139.2	148.7
Ontario 20-minute system peak demand *(MW)*[3]	24,768	25,505	25,145	24,477	24,231
Ontario 60-minute system peak demand *(MW)*[3]	24,636	25,450	25,075	24,380	24,195
Total transmission lines *(circuit-kilometres)*	29,327	28,942	28,951	28,924	29,039
Distribution					
Units distributed to Hydro One customers *(TWh)*[3]	29.2	29.2	29.1	28.9	29.9
Units distributed through Hydro One lines *(TWh)*[3,4]	42.4	42.5	42.5	43.5	44.7
Total distribution lines *(circuit-kilometres)*	121,525	120,514	123,552	123,528	123,260
Customers	1,381,926	1,365,379	1,345,177	1,333,920	1,325,745
Total regular employees	5,811	5,781	5,717	5,427	5,032

[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.

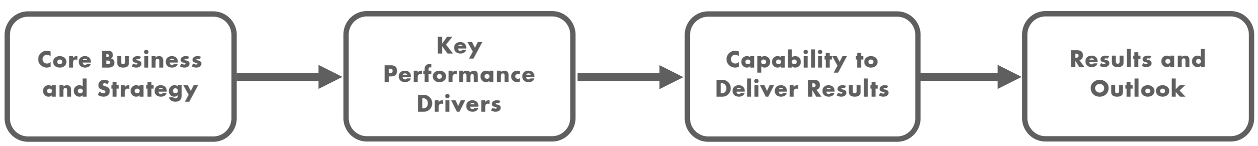
[4] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

We prepare our Consolidated 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, 2011 and 2010.

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, excellence, stewardship 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, 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 2011, we continued to focus on our core businesses and our commitment to our customers, substantially maintained and improved our performance in various key areas of our company, and made important contributions to the rebuilding of Ontario's core infrastructure while continuing 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 mission and vision and our values. Our strategic goals, which are discussed in the section Our Strategy, 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 track the number of customers being billed on time-of-use (TOU) pricing as an indication of our commitment to continuous innovation and use the Collaborative Planning Index as an indication of our commitment to productivity and cost-effectiveness. 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 in the section Performance Measures and Targets.

Capability to Deliver Results

We continue to use a balanced scorecard approach as we strive to manage our key performance drivers and deliver results each and every year. In 2011, we set 17 stretch targets and we met or exceeded 13 of them, consistent with our prior year results when we met or exceeded 14 of 18 stretch targets. We will enable clean and renewable energy in Ontario with the implementation of our Bruce to Milton Transmission Reinforcement Project that will create Ontario's new clean energy corridor. We successfully met our target for customers consuming power on TOU pricing by June 30, 2011. By the end of the year, we had over 1,190,000 customers consuming power on TOU pricing. We exceeded our target for minimizing the duration of unplanned customer interruptions within our Transmission Business. The results of our efforts are fully discussed in the section Performance Measures and Targets. 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 in the section Risk Management and Risk Factors.

Results and Outlook

During 2011, our financial fundamentals remained strong, with current year net income of $641 million. Our OEB-approved revenue requirements for our transmission and distribution businesses for 2011 were $1,346 million and $1,218 million, respectively. 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 $700 million in debt financing, while repaying $500 million of debt maturing in the year. A full discussion of our results of operations and financing activities can be found in the sections Results of Operations and Liquidity and Capital Resources.

In 2011, we invested more than $1.4 billion in capital expenditures to improve system reliability and performance, address an aging power system, facilitate new generation and improve service to customers. Capital expenditures for the next few years include those required to build critical infrastructure identified in the Long-Term Energy Plan (LTEP), based on recommendations from the Ontario Power Authority (OPA) and expenditures to address aging infrastructure. Our future capital expenditures are more fully described in the section Future Capital Expenditures.

OVERVIEW

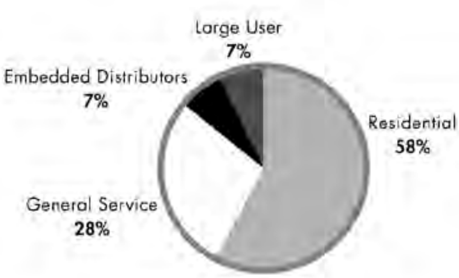
Transmission

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 2011, we earned total transmission revenues of $1,389 million primarily by transmitting approximately 141 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 which 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, 2011
(CAD $ millions)

Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province. We serve approximately 1.4 million rural and urban customers, local distribution companies (LDCs) connected to the distribution system, and 435 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 2011 of $4,019 million. As illustrated in the accompanying chart, over 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.



2011 Distribution Revenues

Other

Our other business segment contributed revenues of $63 million in 2011 and has assets of about $652 million, which represents 3% of our total assets. This segment primarily represents the operations of our wholly-owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements, 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, those who work on our property and the public.

Excellence: We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality and cost-effective service, with integrity.

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 are inextricably linked. 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 represents one of our core values and is critical to achieving our mission and vision. 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. The Advanced Distribution System (ADS) is a key element in our investment in innovation and will improve operation of our grid assets and deliver further value to our customers.

Building and maintaining reliable, cost-effective transmission and distribution 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 ADS technology to provide greater visibility; increasing control and improving customer service; supporting the connection of renewable energy sources; seeking efficiencies through leveraging technology and operational experience from our transmission system; providing reliable and cost-effective service over a diverse geography; and remaining open to opportunities to rationalize the distribution sector.

Protecting and sustaining the environment for future generations. Consistent with our value of stewardship, we play 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 corporate culture, 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.

Maintaining 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.

Achieving productivity improvements 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 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 2011, we met or exceeded 13 of 17 stretch targets. Overall, we are making progress towards achieving our strategic goals.

Creating an injury-free workplace and maintaining public safety

Safety is the primary focus of our company and is our first key strategic objective. The safety of our employees is paramount. For 2011, we established medical attentions, that is, injuries that require treatment by a medical practitioner (beyond first aid), as the performance measure for this strategic objective. The medical attentions measure reflects incidents that are reported to the Workplace Safety Insurance Board and is calculated by the number of attentions per 200,000 hours worked. In 2011, we set a target of no higher than 2.2 incidents per 200,000 hours worked. In an effort to achieve this target, we engaged in a number of activities such as, among other things, continued emphasis on improving health and safety through face-to-face sessions, continuation of our Journey to Zero initiative, better monitoring of mandatory skills and safety training, enhanced driver training/evaluation program and field coaching to increase the expectations from supervisors and staff. The number of incidents in 2011 increased and as a result we did not meet this target.

Satisfying our customers

Customer satisfaction measures the degree to which our transmission and distribution customers are satisfied with the service they receive from our company. Corporate reputation is also a key influencer in customer satisfaction. We continue to focus on improving our reputation. Customer satisfaction is measured on the results of various customer surveys conducted on our behalf by independent third parties. In 2011, for transmission customers we targeted a customer satisfaction rate of 89% and did not meet this target. For our distribution customers, we targeted a satisfaction rate of 85%, but did not meet this target.

Despite these results, we were honoured by the E Source Review as ranking third in Canada among electric and gas utilities in delivering positive customer experience through our automated phone system - interactive voice response system. Additionally, we received the Canadian Electricity Association's (CEA) Sustainable Electricity Social Responsibility Award in recognition of our leadership in engaging our stakeholders. One of the projects recognized by this award is our outreach at fairs across the province to deliver the "Understanding Your Power" event to customers and stakeholders.

Focusing on continuous innovation to ensure a modern, flexible and advanced distribution system

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 costs. Billing customers on TOU rates is the last step in the implementation of our Smart Meter Project. We established a milestone of 1,050,000 customers consuming power on TOU rates for 2011. The Green Grid Enablers are an integral part of meeting the GEA and our strategy towards embracing innovation. Our target is a percentage completion of a number of milestones for the combined Smart Meters TOU Billed and Green Grid Enablers which are projects designed to meet the objectives of the GEA. Our target was to complete 90% of all milestones established for all these initiatives by year end. For 2011, we exceeded our target.

We were honoured and recognized with two awards in 2011. We received the Apex Award, given by the Utilities Telecom Council, in recognition of how our communications systems demonstrate excellence, innovation and service to the communities we serve and in recognition of the installation of six WiMax base stations to provide wireless communications for testing the smart grid applications. As well, we received the Excellence in Project Management Award, given by Utilimetrics, in further recognition of our smart meter deployment and conversion of customers to TOU billing.

Building and maintaining reliable, cost-effective transmission and distribution systems

We aim to build and retain public confidence and trust in our operations, as stewards of Ontario's electricity grid. In 2011, 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 customers in a safe, reliable and efficient fashion. Transmission reliability is measured through the frequency and duration of unplanned customer interruptions. Distribution reliability is measured through the duration of customer interruptions. The results of our performance are compared with other large sized members of the CEA. Reliability is influenced by weather patterns and accordingly, to achieve results, we require good performance from both our transmission and distribution systems. We are conscious that businesses of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration of interruption.

With respect to transmission, in 2011, we targeted 0.25 interruptions per delivery point for our frequency of unplanned interruptions. The actual year-end frequency of unplanned customer interruptions was 0.21. We more than met the target.

For duration of unplanned customer interruptions on the transmission side, the target was 15 minutes per delivery point. The duration of unplanned customer interruptions at year-end was 8.9 minutes. We more than met the target.

On the distribution side, the target for 2011 for the duration of customer interruptions was set at 6.8 hours per customer. Due to a number of storms in December 2011 interrupting a large number of customers over several days, the duration of customer interruptions over the year was negatively impacted. As a result, the duration of interruptions was 6.9 hours, or 0.1 hours higher than target; we did not meet our target.

Protecting and sustaining the environment for future generations

Our initiatives to protect the environment are aligned with the GEA and show our commitment to the delivery of renewable clean energy. We developed three key performance measures for 2011: (i) LTEP and the Bruce to Milton Transmission Reinforcement Project; (ii) greenhouse gas reduction and (iii) Conservation and Demand Management (CDM).

The Province's LTEP, released in 2010, indentifies 5 priority projects to be completed by 2018 that will ensure that the growing mix of renewable generation can be reliably transmitted across the province. Under the LTEP, we are to develop three of these projects. These three priority projects and our continued work on the Bruce to Milton project align with our commitments to protect the environment and support the GEA. For the LTEP, we targeted completion of milestones leading to the successful completion of the development phases of the three projects. Regarding the Bruce to Milton Transmission Reinforcement Project, we targeted a 90% completion of critical milestones by selected dates within 2011. We exceeded our target with respect to the LTEP projects and the Bruce to Milton Transmission Reinforcement Project for 2011.

With respect to greenhouse gas reduction, we established a target of 2,736 metric tonnes of greenhouse gas removed through our initiatives related to our (a) vehicle fleet program (150 tonnes), (b) sulphur hexafluoride gas (SF_6) (2,536 tonnes), and (c) facilities electricity (50 tonnes). We achieved an aggregate of 3,555 metric tonnes of greenhouse gas removed from these initiatives, thus exceeding our target.

Regarding CDM, we are required to comply with the OEB's CDM Code and achieve targets established for us during the period of 2011 to 2014. For 2011, we established a corporate plan to achieve 90% of the milestones we set for those programs for 2011. We exceeded our target for 2011 by completely meeting all milestones.

Employee engagement

Our greatest assets are our employees. We continue to focus effort, specifically in employee and management development activities, on increasing employee engagement throughout our company. An engaged workforce is one in which employees embrace the corporate values of safety, stewardship, excellence and innovation. The process of measuring and improving such engagement began in 2008 by means of an employee engagement survey administered by an independent third party expert and the target is to improve the grand mean score year-over-year. The response rate in 2011 was the largest received to date, with an 86% participation rate. The target of improving the grand mean score to 3.79 (out of 5) in 2011 from the actual result of 3.70 in 2010 was achieved as we exceeded our target with a score of 3.94.

Maintaining a commercial culture that increases value for our shareholder

Achievement of strong financial performance is measured by our two performance measures of net income and a strong credit rating. Our targets were $613 million net income and an "A" category credit rating. Net income for 2011 was $641 million; we met our target. Our long-term credit ratings provided by Standard & Poor's (S&P), Moody's Investors Service Inc. and DBRS Limited met the targeted "A" rating category. Maintaining an "A" category credit rating allows us to have access to long-term debt markets on a cost-effective basis, which is even more critical in the current financial market environment and given our capital requirements over the medium term.

Achieving productivity improvements and cost-effectiveness

One of our strategic objectives is to be productive through efficiency improvements and effective management of costs. The measures for this objective for 2011 were: transmission unit cost, distribution unit cost, Collaborative Planning Index and Cornerstone savings.

To meet our goals regarding transmission unit costs and distribution unit costs, we benchmarked our company against electricity industry-wide measures of productivity. The two most comparable benchmark measures are transmission unit cost, calculated as sustaining capital and operation, maintenance and administration (OM&A) per asset on a percentage basis, which is expressed as cost per asset value for the Transmission Business and distribution unit cost, calculated as capital and OM&A per kilometre of line, which is expressed as cost per line length for the Distribution Business. These were set as our performance measures. Our objective with our ongoing work and investment program is to maintain and improve our assets such that delivery reliability for our customers is maintained or improved and to be productive in how we do that work. To benchmark our performance and monitor our productivity year-over-year, we set cost targets which are measured within a range of plus or minus 5%. Our transmission unit cost target was set at 5% and we met this target. Regarding our distribution unit cost, our cost target was set at $6,800 per kilometre of line and we also met this target.

The Collaborative Planning Index is a measure of the effective workflow between lines of business and the resulting efficiencies enabling field crew productivity. The Collaborative Planning Index is based on the average of three metrics: release of work, which is the release of funds at the program and project level for work defined and agreed to by the operations groups; planning index, which is the percent measure of the total number of material orders entered into the system divided in accordance with lead times agreed to by the stakeholders; and order fill rate, which is the percent measure of the total number of material orders divided into the number of line orders that have been delivered to the right location at the right time. For 2011, we set the target for the average of the three metrics at 87% and we exceeded this target.

Cornerstone is our phased replacement of key enterprise information technology systems. Savings from this initiative are derived by looking at a wide range of processes to identify savings across the various lines of business. Our target for 2011 was $38.5 million in savings and we achieved $41.3 million in savings through strategic sourcing of materials, reduction in employee headcount, and reduction in the number of information technology applications and their attendant support costs, thereby exceeding this 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.

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 previously set prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Currently, it also sets prices for RPP customers based on a three-tiered electricity pricing structure with TOU thresholds. Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the 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 TOU rates. On August 4, 2010, the OEB issued a Final Determination to mandate TOU pricing for RPP consumers by establishing a mandatory TOU date for each electricity distributor. This Final Determination mandated that all eligible RPP customers be transitioned to TOU pricing by June 2011. On September 16, 2010, we filed an application with the OEB for an exemption from the mandated TOU 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 at June 30, 2011, we had over one million customers consuming power based on TOU pricing, meeting our OEB target. By the end of 2011, we had transitioned the majority of our remaining customers to TOU rates. For the final 150,000 exempted customers, we continue to evaluate different options.

As announced in the 2010 Ontario Economic Outlook and Fiscal Review, 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 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 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.

GEA and LTEP

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) and submitted it 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 then 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 then Minister of Energy and Infrastructure requested that our company 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 that are critical to the connection of renewable generation projects that have been identified by the OPA as part of the Province'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 process. On March 29, 2011, the Minister of Energy expressed the Province's interest in the OEB commencing a designation process for the East-West Tie Line. The proposed route is a 400 km, 230 kV double-circuit line to run beside an existing Hydro One Networks Inc. (Hydro One Networks) transmission corridor along the north shore of Lake Superior between Hydro One Networks' transformer stations at Wawa in the east and Lakehead in the west. The target in-service date, set by the OPA in its report issued June 30, 2011, is 2017. The East-West Tie LP, an equally-shared partnership of three entities including Hydro One, is currently seeking a transmission licence to participate in the East-West Tie bid process. There are six other potential bidders that are interested in this project. The OEB convened a series of meetings with all potential bidders, the OPA, the IESO and incumbent transmitters in January and February 2012, to discuss the specifics of the process. On February 2, 2012, the OEB issued a Notice of Proceeding, inviting all registered transmitters to file a development plan. The date for filing of plans will be set in due course.

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 to be approved by the OEB that identify expansion or reinforcement of the distribution system 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 to it by the then Minister of Energy and Infrastructure. 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 October 31, 2011, the Ministry of Energy announced the commencement of the planned review of the FIT Program. The review will consider a range of issues including a FIT price reduction. New prices for FIT contracts will be carefully developed to balance the interests of ratepayers with the need to encourage investments in new clean energy. The review will not affect FIT contracts in existence prior to October 31, 2011. All other applications will be subject to the new rules and pricing schedule once the FIT Program review is complete. The review provided an opportunity for feedback and written submissions until December 14, 2011. We submitted comments and participated in the review process in a number of forums.

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. On February 17, 2011, the Province issued a Supply Mix Directive that requires the OPA to prepare a 20-year IPSP to meet the goals set out in the LTEP. The Supply Mix Directive will form the basis for the new IPSP. On May 9, 2011 the OPA announced that it was beginning consultations to update Ontario's IPSP and issued the *IPSP Planning and Consultation Overview* document. A series of four consultation sessions occurred during the month of May. The OPA asked stakeholders to provide input into the IPSP by June 17, 2011. We submitted our comments on that day. Stakeholder comments will form part of the evidence when the OPA submits the revised IPSP to the OEB for review.

On February 28, 2011, the OEB issued a decision amending Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy to the OEB. The licence amendment requires Hydro One Networks to develop and either seek approvals for or implement specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy in accordance with recommendations from the OPA. In a letter dated April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at 10 of 15 transformer stations noted in the licence to accommodate small-scale renewable generation. Alternative solutions have been identified for three of these stations and the recovery of the other seven station upgrades is restricted (see Future Capital Expenditures). On June 30, 2011, we received a letter from the OPA recommending the scope and timing to reconductor two circuits between Sarnia and London, the West of London Transmission Upgrade Project, to enable the connection of additional renewable generation in the west of London area with a required in-service date of December, 2014. On October 3, 2011, we received a letter from the OPA recommending the scope and timing of the Southwestern Ontario Reactive Compensation Priority Project, formerly the Southwestern Ontario Series Compensation Project. After consideration of the options, the OPA has recommended that we install a Static Var Compensator (SVC) at our Milton Switching Station to increase the capability of the Bruce transmission system. We are awaiting an OPA recommendation regarding the construction of a new transmission line west of the City of London.

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, in respect of its Distribution Business, filed an application with the OEB requesting an exemption from certain cost responsibility rules contained in the DSC for distributed generation (DG) projects under the Renewable Energy Standard Offer Program. 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.

On October 11, 2011, the OEB issued its decision pertaining to an application we filed on April 19, 2011 requesting an exemption from the DSC timelines for the connection of micro-embedded generation facilities. Since the inception of the microFIT Program, we have issued over 10,000 Offers to Connect, of which over 7,600 projects have been connected as at December 31, 2011. The exemption was requested to manage the anticipated high volume of micro-embedded generator applications, manage summer construction, new connects and high load periods and make necessary revisions to business processes. The OEB decision increases the timeline for processing indirect connections that require a site assessment from 15 days to 30 days. The OEB also approved amendments to the conditions that must be met before we are required to connect micro-embedded generation facilities to the distribution system. Connections must now be performed within 5 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to with the customer. The exemption expires on April 11, 2012. On December 14, 2011, the OEB issued an order requiring us to file our first compliance report by January 3, 2012 and on a monthly basis thereafter, until we have met the DSC requirements for three consecutive months.

CDM

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 and Hydro One Brampton Networks Inc. (Hydro One Brampton), as a result of OEB program requirements . Our CDM programs funded through the OPA in 2011 amounted to approximately $15 million, compared to $31 million in 2010. 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 then Minister of Energy and Infrastructure's March 31, 2010 directive set a province-wide 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 (CDM Code). On the same day it issued proposed specific CDM targets for all LDCs as directed by the then Minister of Energy and Infrastructure earlier that year. The CDM Code was issued by the OEB on September 16, 2010. On November 12, 2010, the OEB issued final CDM targets to each LDC. The allocation of the overall targets to our company are a 259 MW reduction of provincial peak demand and a 1,320 GWh reduction of electricity consumption, representing, respectively, 19.5% and 22.0% 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. We do not intend to file an application for OEB-approved programs.

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 capable of measuring and reporting usage over predetermined periods, being read remotely, and, when combined with communications systems, are 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 TOU rates. In 2010, we continued our focus on building an ADS and launched our initiative to leverage the infrastructure from our earlier smart meter investments. In 2011, we carried out a number of studies on advanced distribution technologies and initiated the Smart Zone Pilot Project in the Owen Sound area. The Smart Zone Pilot consists of testing and demonstrating power system equipment, IT systems and communication systems that will be required to help facilitate the connection of a large number of DG connections to the distribution system. Further releases of the ADS will look at optimizing outage response through more effective dispatch, automation to isolate faults where needed and the dynamic regulation of voltage to reduce losses. All releases leverage a core set of infrastructure and build on each other, and as pilot elements are proven, business cases will be developed for the provincial roll out which will ultimately comprise the ADS.

Renewed Regulatory Framework

On December 17, 2010, the OEB initiated a coordinated consultation process for the development of a renewed regulatory framework for electricity distributors and transmitters. This effort is intended to help ensure the reliable and cost-effective delivery of electricity to Ontario consumers in light of the significant anticipated investment needed for the renewal of existing assets and to connect new generation.

On November 8, 2011, the OEB released five staff discussion papers and supporting consulting reports that are intended to initiate dialogue with stakeholders. These papers and reports looked at many issues including: distribution network investment planning; regional planning; smart grid (our version is ADS); rate mitigation/smoothing; and performance measurement. The anticipated outcome of this initiative is a regulatory framework with several potential areas of change including rate design, system codes, cost allocation, cost responsibility, reporting requirements and a performance measurement matrix.

Transmission Rates

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

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 returns on equity (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 lower approved ROEs of 8.01% and 8.16%. The decision also required the establishment of new regulatory accounts to track the difference between the forecasted and actual external revenues for export services, secondary land use and net maintenance services provided primarily 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 11, 2009, the OEB issued its final report on its cost-of-capital review that concluded that the formula-based ROE needed to be reset and refined. 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 May 19, 2010 we submitted an application for 2011 and 2012 transmission rates in continued support of our aging critical infrastructure and 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 represented estimated rate increases 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 of Ontario distributors and transmitters, issued in January, 2009.

On December 23, 2010, the OEB issued its decision, which resulted in a revenue requirement effective January 1, 2011 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, or 0.5% and 2%, respectively on an average customer's total bill. 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 on the construction work-in-progress for our Bruce to Milton Transmission Reinforcement Project and an envelope OM&A reduction. Our 2012 revenue requirement was also impacted by the above-noted factors, but was higher than we originally submitted due to the OEB directing us to adopt a capitalization policy that was consistent with modified International Financial Reporting Standards (IFRS). This specific revision resulted in an increased revenue requirement of about $200 million for 2012.

On January 17, 2011, the Power Workers Union (PWU) 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 OM&A costs and therefore, that a legal error was made. The appeal has not affected the collection of the 2011 transmission rates. The appeal in this matter was heard by the Divisional Court in October, 2011. A decision is currently pending.

Consistent with our approval from the Ontario Securities Commission (OSC) to adopt United States (US) Generally Accepted Accounting Principles (GAAP) for external financial reporting and securities filings, on July 15, 2011 we filed a Motion to Vary the OEB's 2012 rate decision. Our application sought approval to adopt US GAAP as a basis for regulatory accounting and rate setting in place of the OEB's approved modified IFRS basis. The adoption of US GAAP in lieu of modified IFRS decreases the 2012 revenue requirement by the same $200 million adjustment that was made by the OEB in its 2012 decision.

In response to our Motion to Vary, the OEB on its own motion held a written proceeding to review our request to adopt US GAAP for rate-setting purposes. On November 23, 2011, the OEB issued its decision with reasons that approved the use of US GAAP by our Transmission Business. The decision also approved adjustments to our 2012 transmission revenue requirement, capital expenditures and rate base consistent with those we proposed in our evidence. The OEB also approved creation of several new US GAAP regulatory accounts.

On December 1, 2011, we submitted to the OEB a draft 2012 transmission revenue requirement that reflects the approved adoption of US GAAP for rate-setting purposes as well as the OEB-directed update to 2012 cost-of-capital parameters. On December 20, 2011, the proposed $1,418 million 2012 revenue requirement was approved by the OEB along with new 2012 UTRs effective January 1, 2012. The new rates result in an approximate 8% transmission rate increase, or 0.6% on an average customer's total bill. The adoption of US GAAP in lieu of modified IFRS has decreased the revenue requirement in 2012 by approximately $200 million and decreased the approved rates by 15%.

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 established a multi-year electricity distribution rate-setting plan whereby a distributor's rates are set via a cost-of-service rebasing application in one of the years 2008, 2009, 2010 or 2011. Following the year of rebasing, a distributor would be subject to an Incentive Regulation Mechanism (IRM) that uses a formulaic approach to establish rates for the next three years. The third-generation IRM plan currently in effect establishes a pre-defined set of conditions under which the IRM plan could be terminated allowing for a utility to file a cost-of-service application.

Hydro One Networks

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. An updated application was filed on September 25, 2009. The revised application sought OEB approval of revenue requirements of approximately $1,150 million and $1,264 million based on ROEs 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 an ADS. 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 our requested OM&A expenses, capital expenditures and working capital requirements. As part of its decision, the OEB also approved disposition of certain distribution-related regulatory account balances we sought 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 to be recovered over an 18-month period from May 1, 2010 to December 31, 2011. Further, the OEB requested the establishment of new regulatory 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. These differences are tracked in the regulatory account we refer to as Rider 8.

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 also 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 produced a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement resulted in an average distribution rate increase of approximately 8.7% for 2011, or 3.0% on an average customer's total bill.

Given the close relationship between Hydro One Networks' transmission and distribution businesses, we originally included a request to allow our Distribution Business to adopt US GAAP for rate-setting purposes as part of our Transmission US GAAP application. In its November 23, 2011 Transmission Business decision, the OEB determined that it would not make a decision on the Distribution portion of our request for procedural reasons but did indicate that it would consider a stand-alone application requesting the extension of the use of US GAAP to our Distribution Business. On December 1, 2011 we submitted our application requesting that the OEB approve the use of US GAAP in place of modified IFRS for rate-setting purposes within our Distribution Business effective January 1, 2012. In our application, we estimated that a 2012 notional Hydro One Distribution revenue requirement would be $166 million higher under modified IFRS compared to US GAAP, primarily due to differences in capitalization policy. We also indicated that we are not requesting any change to our approved distribution rates at this time. A decision on our request to adopt US GAAP for our Distribution Business is anticipated in the first quarter of 2012.

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. This incorporates an OEB-approved formula that considers inflation and efficiency targets. On March 13, 2009, the OEB issued its decision with reasons and revised rates, including an amount of $1 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 deferral of the adoption of modified IFRS until January 1, 2012. The updated submission was filed on November 8, 2010 and requested OEB approval for a revenue requirement of approximately $63 million. On April 4, 2011, the OEB issued a decision with reasons that reduced the requested revenue requirement. This reduction included the impact of reductions to OM&A costs. The revised rates were approved with an effective date of January 1, 2011 and an implementation date of May 1, 2011. Included in the rates is an amount of $1.52 per month per metered customer for smart meters and approval of a GEA funding adder of $0.02 per month per metered customer. The new rates result in a total bill increase for an average customer of approximately 0.5%.

On September 15, 2011, Hydro One Brampton filed an application for 2012 rates on the basis of the OEB's third-generation IRM process. In its application, it requested recovery of lost revenues associated with load reduction related to energy conservation programs. Hydro One Brampton requested approval for a Lost Revenue Adjustment Mechanism and disposal of the provision for payments in lieu of corporate income taxes (PILs) regulatory account balance. On December 22, 2011, the OEB issued its decision on the application, directing Hydro One Brampton to file a draft Rate Order by December 30, 2011. The draft Rate Order was filed on December 28, 2011 and on December 31, 2011, the OEB declared Hydro One Brampton's existing rates interim as of January 1, 2011. On January 5, 2012, the OEB released a decision with reasons that resulted in a reduction in rates of approximately 13.2%, or a 1.7% reduction on the average customer's total bill in the year. These rate reductions were primarily due to OEB-approved adjustments to existing depreciation rates.

Hydro One Remote Communities Inc. (Hydro One Remote Communities)

On November 4, 2009, our subsidiary Hydro One Remote Communities filed its application for 2010 rates under the OEB's third-generation IRM. This application sought OEB approval for an increase to basic rates for the distribution and generation of electricity effective May 1, 2010. The requested rate increase reflected the standard inflationary adjustments incorporated in third-generation IRM applications. On April 14, 2010, the OEB issued a decision with reasons regarding this rate application. Revised rates were approved for implementation effective May 1, 2010 and reflected an increase of approximately 0.4%, for which the overall impact on an average customer's total bill was 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. On March 28, 2011, the OEB issued its decision approving the application with an effective date and implementation date for the new rates of May 1, 2011. The overall impact of the new rates on an average residential customer's total bill was marginal.

On November 25, 2011, we filed an application for 2012 distribution rates 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, 2012. We expect to update our rate application when the OEB issues its inflation and productivity factors for IRM filers in the first quarter of 2012.

Consistent with the OEB's decision affirming the use of US GAAP for rate-setting purposes by Hydro One Networks' Transmission Business, on December 15, 2011, we made a similar request to use US GAAP for Hydro One Remote Communities. We anticipate a decision in the first quarter of 2012.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	2011	2010	$ Change	% Change
Transmission	1,389	1,307	82	6
Distribution	4,019	3,754	265	7
Other	63	63	-	-
	5,471	5,124	347	7
Average annual Ontario 60-minute peak demand *(MW)*[1]	21,166	21,572	(406)	(2)
Distribution – units distributed to customers *(TWh)*[1]	29.2	29.1	0.1	-

[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 influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and to secondary use of our land rights-of-way.

Our transmission revenues were higher by $82 million, or 6%, compared to 2010. This increase was primarily due to higher tariff revenues of $87 million resulting from a December 23, 2010 OEB decision on the 2011 and 2012 transmission rate application by our subsidiary, Hydro One Networks, consistent with our allowed ROE. The decision followed extensive oral and written reviews of evidence we submitted for the funding necessary to support our system requirements. The resulting rates, which were effective January 1, 2011, support our investments to address aging critical infrastructure, supply mix objectives for generation including off-coal initiatives, and the initiation of investments in support of the GEA. Ancillary revenue for the year was higher by $16 million than in 2010 due to increased external revenues. We also experienced higher export service revenue of $4 million, compared to the prior year. Export service and external amounts received in excess of approved levels are recorded in a regulatory account.

Revenues for the year also reflect lower average peak demands compared to last year, resulting in a decrease in transmission revenue of $13 million. The average annual Ontario 60-minute peak demand and the overall related load were 406 MW and 4,866 MW lower than last year, respectively. Among other factors, we experienced milder weather in the third and fourth quarters, compared to 2010.
We also experienced lower transmission revenues associated with OEB-approved regulatory accounts of $12 million compared to last year, mainly related to the full recovery of a transmission regulatory account at the end of last year.

Distribution

Distribution revenues include our distribution tariff, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our approved distribution tariffs. 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 $265 million, or 7%, compared to 2010. After excluding higher purchased power costs of $154 million, as described below in the section Purchased Power, the increase was $111 million, or 9%.

After considering purchased power costs, increases in revenue reflect two OEB decisions on the distribution tariff rates of our subsidiary, Hydro One Networks. On April 9, 2010, the OEB approved new tariff rates effective May 1, 2010 and on December 21, 2010, the OEB approved new tariff rates effective January 1, 2011, consistent with our allowed ROE. Both OEB decisions followed extensive written and oral reviews of the evidence we submitted for the maintenance and investment requirements of our distribution system. The combined impact of these decisions was an increase in distribution revenues of $93 million. These tariff rate increases enable the safe and reliable delivery of electricity to our customers throughout Ontario and begin the development of the ADS to ensure the future integrity of our system as we connect large volumes of new DG. In addition, we experienced higher smart meter revenues of $18 million during the year, reflecting the recovery of our increased expenditures incurred consistent with higher levels of in-service smart meter assets. We have met the OEB requirements for smart meters and the transition to TOU and continue to work with the IESO on enhanced systems functionality.

Higher energy consumption, resulting primarily from the colder winter at the beginning of this year, increased our distribution revenues by a further $6 million. We also experienced increased other revenues of $2 million for the year. Distribution revenue increases were partially offset by a revenue reduction of $8 million compared to the prior year associated with the full recovery of a distribution-related regulatory account effective April 30, 2010.

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 IESO's wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on TOU billing, both of which are adjusted twice annually. We began transitioning our RPP customers to TOU billing May 1, 2010 and, as noted, the majority of our RPP customers are now on TOU billing. Customers who 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 and comparative periods 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, 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
May 1, 2011	600	750	6.8	7.9
November 1, 2011	1,000	750	7.1	8.3

RPP TOU	**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
May 1, 2011	10.7	8.9	5.9
November 1, 2011	10.8	9.2	6.2

Purchased power costs increased in 2011 by $154 million, or 6%, to $2,628 million for the year compared to 2010. The increase in our purchased power costs was primarily due to: the impact of changes in the OEB's RPP rates for residential and other eligible customers of $75 million; higher purchased power costs of $56 million for customers who are not eligible for the RPP; increased transmission charges of $24 million due to the OEB's transmission rate decision effective January 1, 2011; and the impact of higher demand for electricity of $2 million. The effect of these increases was partially offset by lower charges levied by the IESO of $3 million.

OM&A

Our OM&A 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.

OM&A costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**	**$ Change**	**% Change**
Transmission	422	416	6	1
Distribution	609	602	7	1
Other	61	60	1	2
	1,092	1,078	14	1

Transmission

OM&A expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $6 million, or 1%, in 2011 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 requirements were higher by $39 million compared to last year. During the year, we incurred expenditures of $19 million related to the OPA's recommendation to increase short circuit and/or transformer capacity at 10 of our transmission stations to enable the connection of small renewable projects, for which recovery is restricted (see Future Capital Expenditures). In addition, we experienced higher requirements for station maintenance for power equipment, maintenance to repair aging underground cables and higher requirements related to the fire at our Richview Transformer Station. Our crews worked tirelessly to rebuild and place in-service the impacted aging transformers to ensure adequate supply to critical LDCs. We also experienced higher requirements for our forestry program. Our expenditures in support of our transmission system have decreased by $33 million reflecting lower telecom expenditures from lower long distance rates associated with leveraging broader public sector rates on voice domain, lower data usage and lower support costs. Also, we made an additional contribution of $27 million to our pension plan in the last quarter of 2010.

Distribution

OM&A expenditures required to maintain our low-voltage distribution system increased by $7 million, or 1%, compared to last year. Our work program expenditures increased by $16 million primarily related to increased power restoration expenditures as the province experienced a higher volume of storm activity, as well as increased requirements associated with unplanned system changes to implement OEB code amendments impacting our billing system. This was partially offset by lower expenditures for our line patrol program as a result of new data collection methods, lower field meter reading expenditures and a lower forestry program this year. Our expenditures in support of our distribution system decreased by $9 million, reflecting lower telecom costs and other support costs. We also made an additional contribution to our pension plan of $21 million in the last quarter of 2010. These costs were partly offset by a redirection of resources in support of DG programs.

Depreciation and Amortization

Depreciation and amortization expense increased by $33 million, or 6%, to $616 million in 2011 compared to the prior year. The increase was mainly attributable to higher depreciation of approximately $29 million related to the placement of new assets in service, consistent with our ongoing capital work program. We also experienced an increase of $9 million as a result of an increase in fixed asset removal costs associated with storm restoration and fire restoration work during the year. Amortization of regulatory and other assets decreased by $6 million, mainly due to the full recovery of a distribution regulatory account during the second quarter of last year.

Financing Charges

Financing charges increased by $2 million, or 1%, to $344 million for 2011 compared to 2010. The increase is mainly due to a $9 million increase in long-term debt interest expense primarily as a result of an increased average level of debt, partially offset by a lower average effective interest rate. This increase was partially offset by higher interest capitalized of $3 million reflecting higher levels of construction-in-progress consistent with our growing capital program and favourable changes in interest income and other ancillary amounts which reduced overall financing charges by $4 million.

Provision for Payments in Lieu of Corporate Income Taxes

We make 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 PILs, 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-setting process, results in a future tax provision that is charged to the Consolidated Statement of Operations. The change in future taxes relating to temporary differences of the regulated businesses that are considered for the rate-setting process results in a regulatory asset or regulatory liability.

The provision for PILs increased by $94 million, or 168%, to $150 million compared to 2010. The increase was primarily due to changes in net temporary differences, including lower capital cost allowance claimed on software than in the prior year, and higher pre-tax income in the year. Net increases in 2011 were partially offset by a reduction in the statutory tax rate from 31.00% to 28.25%.

Net Income

Net income of $641 million was higher than our comparable 2010 results by $50 million, or 8%. Net income reflects OEB rate decisions that allowed for, among other things, the recovery of capital investments from prior years that are now in-service. New assets in service include investments to address our aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives, and investments in support of the GEA. Higher revenues were partially offset by higher operating expenditures, including those related to our non-recoverable work to increase short circuit and/or transformer capacity at some of our transmission stations to enable the connection of small renewable projects, and by a higher effective tax rate.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2010 through December 31, 2011. This information is 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)	**2011**				**2010**			
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**
Total revenues[1]	1,359	1,384	1,268	1,460	1,280	1,360	1,165	1,319
Net income[1]	120	167	142	212	99	218	105	169
Net income to common shareholder[1]	115	163	137	208	94	214	100	165

[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, other investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Operating activities	1,407	1,164
Financing activities		
Long-term debt issued	700	1,500
Long-term debt retired	(500)	(600)
Short-term notes payable	-	(55)
Dividends paid	(168)	(28)
Investing activities		
Capital expenditures	(1,447)	(1,570)
Long-term investments[1]	-	(250)
Other financing and investing activities	28	37
Net change in cash and cash equivalents	17	198

[1] Represents $250 million of Province of Ontario Floating Rate Notes.

Operating Activities

Net cash from operating activities increased by $243 million to $1,407 million in the year, compared to 2010. The increase primarily reflects higher net income this year combined with the impact of changes in accounts payable balances related to the timing of customer prepayments and advances for engineering work, increases in taxes payable resulting from required levels of in-year tax installments and changes in certain regulatory account balances.

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 holding 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 our $1,250 million committed revolving credit facility with a syndicate of banks maturing in June 2014 and our 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, 2011, we had $7,975 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2012 and 2051. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. On August 23, 2011, 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 is $3,000 million. As at December 31, 2011, $2,600 million remains available until September 2013.

	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 these covenants and limitations as at December 31, 2011.

In 2011, we successfully issued $700 million in cost-effective long-term debt under our MTN Program, consisting of $300 million in the first quarter, $300 million in the third quarter and $100 million in the fourth quarter. We also repaid $500 million in maturing long-term debt, $250 million in the first quarter and $250 million in the fourth quarter. In 2010, we issued $1,500 million in long-term debt under our MTN Program, $1,000 million in the first quarter and $500 million in the third quarter, and repaid $600 million in maturing long-term debt, $400 million in the second quarter and $200 million in the fourth quarter. In 2011, we did not issue any short-term notes. In 2010, we reduced our short-term notes by $55 million, all in the first quarter, and there were no short-term notes outstanding as at December 31, 2010.

Common dividends are declared at the sole discretion of our 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. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

In 2011, we paid dividends to the Province in the amount of $168 million, consisting of $150 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $10 million and preferred dividends of $18 million. In 2011, cash dividends per common share were $1,500 compared to $100 per common share in 2010. Cash dividends per preferred share were $1.375 in each of 2011 and 2010.

On February 10, 2012, we declared dividends to the Province in the amount of $281 million, consisting of $277 million in common dividends and $4 million in preferred dividends.

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 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)	**2011**	**2010**	**$ Change**	**% Change**
Transmission	810	936	(126)	13
Distribution	628	629	(1)	-
Other	9	5	4	80
	1,447	1,570	(123)	8

Transmission

Transmission capital expenditures decreased by $126 million in 2011 to $810 million, compared to 2010. Expenditures to expand and reinforce our transmission system were $416 million, representing a decrease of $108 million from last year. The majority of our expenditures were made on inter-area network projects to support the Province's supply mix objectives for generation, although we continue to make significant investments on load customer connection and local area supply projects to address growing loads. The year-over-year reduction in our expenditures results from projects that were in their final stages of completion this year. These projects included the installation of complex SVCs at our Nanticoke and Detweiler transformer stations and at our Porcupine and Kirkland Lake transformer stations. We also experienced lower expenditures compared to 2010 due to major inter-area network projects completed and put into service last year, including the installation of capacitor banks in Southwestern Ontario and our Cherrywood Transformer Station to Claireville Transformer Station Connection Project. Local area supply projects that were substantially completed last year included our Greater Toronto Area (GTA) West Transmission Reinforcement Project and our Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection. The impact of the reduction in expenditures was partially offset by an increase in our investments this year in a number of load customer connection projects.

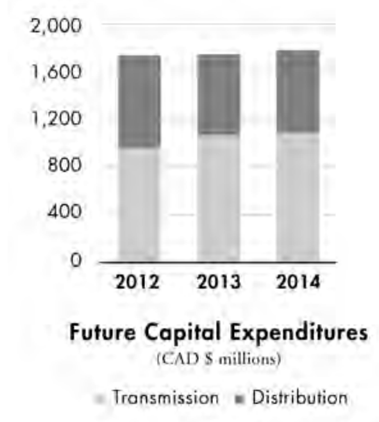
Inter-area network upgrades with significant expenditures this year included our Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. In the fourth quarter, our SVCs at our Nanticoke and Detweiler transformer stations went into service. In the short term, this project supports increased generation from the Bruce Nuclear facility and in the longer term it will enhance the transfer capability between Southwestern Ontario and the GTA. We also installed the SVC at our Kirkland Lake Transformer Station as part of our project to install SVCs at our Porcupine and Kirkland Lake transformer stations. The SVC at our Porcupine Transformer Station went into service late in 2010. This project increases the North-South interface transfer capability to access available northern generation.

Our local area supply project expenditures include investments in our Woodstock Area Transmission Reinforcement Project to increase capacity and ensure supply reliability in the Woodstock area and the Switchyard Reconstruction Project at our Burlington Transformer Station, which will address aging infrastructure and increase the load supply capacity to ensure reliability of supply to customers in the area. During the year, we also commenced work on our Midtown Electricity Infrastructure Renewal project (formerly the Midtown Toronto Project), together with Toronto Hydro-Electric System Limited, to replace aging cable and overhead line facilities and to provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west.

Expenditures to sustain our existing transmission system were $335 million, representing a decrease of $23 million compared to 2010. The reduction was primarily related to lower expenditures to enhance security infrastructure related to the prevention of copper theft, as work was substantially completed in the year, as well as lower expenditures for work on our protection and control systems compared to the prior year due to a re-allocation of resources to development projects. We also incurred lower expenditures related to the strategic purchase of power transformers compared to the prior year. In order to ensure transmission reliability, purchases were made in 2010 for these critical long delivery lead-time items. These reductions were partially offset by increased requirements related to the refurbishment and replacement of end-of-life lines and stations. Our other transmission capital expenditures were $59 million, representing an increase of $5 million compared to the prior year. The majority of these expenditures were related to our fleet and to IT development.

Distribution

Distribution capital expenditures decreased marginally by $1 million to $628 million in 2011, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $269 million, representing a reduction of $68 million compared to last year. We experienced reductions related to the substantial completion of smart meter installations by the end of 2010, and lower expenditures in our wholesale metering program. During the year, we continued to invest in our smart meter network infrastructure and the development and integration of the systems required for TOU billing, including meter reading capability and integration with the IESO meter data repository. Of our 1.3 million customers with smart meters installed as at December 31, 2011, we had over 1.1 million consuming power based on TOU pricing. We also continued to invest in our ADS Project that will enhance our operations and support DG.



Expenditures to sustain our distribution system were $240 million, an increase of $34 million from 2010. During the year, we experienced increased requirements for emergency restoration work as a result of a higher number of storms, including two major storms that hit Ontario in the second quarter. Partially offsetting these impacts were lower expenditures related to reduced work for joint use and relocation of our lines.

Our other distribution capital expenditures were $119 million, representing an increase of $33 million from 2010. This increase is primarily attributable to expenditures for the next phase of our entity-wide information system replacement and improvement project related to our Customer Information System (CIS). In addition to replacing an end-of-life system, the implementation will result in process improvements which will, among other benefits, enhance customer satisfaction through methods such as reduced call times and first call resolution stemming from faster availability of information.

Future Capital Expenditures

Our capital expenditures in 2012 are budgeted at approximately $1.8 billion. The 2012 capital budgets for our transmission and distribution businesses are about $1,000 million and $800 million, respectively. Capital expenditures are expected to be approximately $1.8 billion in each of 2013 and 2014. These expenditures reflect the sustainment requirements of our aging infrastructure, budgeted at approximately $700 million in 2012, $950 million in 2013 and $1,000 million in 2014. Development projects, including ADS, inter-area network upgrades that reflect supply mix policies, local area supply requirements and requirements to enable DG, are budgeted at approximately $750 million in 2012, $600 million in 2013 and $550 million in 2014. These development investments also reflect customer demand work, work to facilitate DG connections and the roll out of our ADS Project. Other budgeted capital expenditures amount to approximately $350 million in 2012, $250 million in 2013 and $250 million in 2014. These expenditures include the replacement of our customer billing system to address end-of-life requirements and to further productivity realization from our enterprise-wide SAP platform.

Transmission

Transmission system capital expenditures are anticipated to be approximately $3.2 billion over the period 2012 to 2014. These include significant investments to manage the replacement and refurbishment of our aging transmission infrastructure in order to ensure a continued reliable supply of energy to customers throughout the province. The investment plan includes sustainment investments for system and stations reinvestment to replace end-of-life air blast circuit breakers, underground cable, auxiliary telecommunications equipment, aging power transformers and to comply with North American Electricity Reliability Corporation cyber security requirements. These sustaining investments are necessary to ensure that we continue to meet all regulatory, compliance, safety and environmental 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. Other planned major capital investments include our Midtown Electricity Infrastructure Renewal Project, that will provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west, our Southwestern Ontario Reactive Compensation Priority Project that will increase the capability of the Bruce transmission system, our Oshawa Area

Transformer Station Project to install additional 500-230 kV auto-transformer capacity within the east GTA as early as the spring of 2015 and our project to rebuild the switching station at our Hearn Transformer Station. Transmission investments for ADS and requirements to enable DG are also included in the investment plan. The Hearn Transformer Station Project, along with four other transformer station upgrades we will undertake, will collectively enable up to 600 MW of new transmission.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work for specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy. The estimated capital expenditures associated with these projects and upgrades to the system are anticipated to be up to approximately $700 million over a period to the in-service dates of these projects. On February 28, 2011, the OEB amended Hydro One Networks' transmission licence in accordance with a directive to the OEB from the Minister of Energy. The licence amendment requires Hydro One Networks to develop and seek approvals for these projects in accordance with recommendations from the OPA. In a letter dated April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at 10 of 15 transformer stations noted in the licence to accommodate small-scale renewable generation. One of these upgrades was completed in 2011 and we are currently anticipating that six station upgrades will be in-service in 2012. For the remaining three upgrades, alternative solutions have been identified. The overall capital cost for the stations is estimated to be up to $50 million. On June 30, 2011, we received a letter from the OPA recommending the scope and timing to reconductor two circuits between Sarnia and London, the West of London Transmission Upgrade Project, to enable the connection of additional renewable generation in the west of London area with a required in-service date of December 2014. On October 3, 2011, we received a letter from the OPA recommending the scope and timing of the Southwestern Ontario Reactive Compensation Priority Project, formerly the Southwestern Ontario Series Compensation Project. After consideration of the options, the OPA has recommended that we install an SVC at our Milton Switching Station to increase the capability of the Bruce transmission system. We are awaiting an OPA recommendation regarding the construction of a new transmission line west of the City of London.

In accordance with the memorandum of agreement between Her Majesty the Queen in the Right of the Province of Ontario as represented by the Minister of Energy (the Shareholder) and our company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. Specifically, the rights, powers and duties of our company's Directors have been restricted with regard to any decisions regarding: the pursuit of cost recovery by Hydro One Networks from microFIT and small-scale (capacity allocation exempt) FIT generation projects or proponents thereof for costs related to investments and expenditures made, or required to be made, by Hydro One Networks in order to appropriately fund the upgrades at up to 15 transformer stations pursuant to the February 28, 2011 licence condition amendment made to Hydro One Networks' transmission licence; the pursuit of cost recovery by Hydro One Networks of such costs through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates; and whether or not to pursue and implement internal cost recovery or cost mitigation measures designed to offset the costs associated with the upgrades, and to pursue further cost minimization strategies and to increase overall cost efficiencies within our company, including the timing of any such decisions. In 2011, we spent approximately $19 million on these projects, which was charged to results of operations.

In August 2010, the OEB introduced a framework for competitive designation of the development of eligible transmission 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. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates, with the exception of the transformer station upgrades noted above.

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.

Distribution

Capital expenditures within our Distribution Business are anticipated to be approximately $2.2 billion over the period 2012 to 2014. These include investments 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 are continuing investments to replace end-of-life equipment and components, implement ADS as part of this renewal and a focus on wood pole replacements to maintain reliability. In addition, we will continue to address the demand for new load connections, trouble calls, storm restoration and system capability reinforcement.

Distribution development expenditures over the period are primarily related to customer demand work such as connections and upgrades, ADS, work to facilitate DG connections, including station upgrades, protection and control, new lines and some contestable work for which we receive capital contributions. During the 2012 and 2013 periods, we expect to manage a significant number of projects throughout the province to address load growth and the stress on our system components.

DG expenditures are based on our estimate of the number of anticipated connections, which have been reduced based on the experience gained since 2009 and changes that have occurred to the FIT Program. The budget only reflects expenditures for projects with FIT and microFIT program contracts from the OPA that are expected to connect to our distribution system.

In 2012, the ADS Project will continue to focus on the development of the technical solution and the beginning of its implementation in areas of the province where operational need is greatest. The early focus will be the integration of the Distribution Management System with intelligent power system electronic devices to support embedded DG, but it will also leverage the integration of the existing outage management system and automate crew dispatch.

Our current billing system is near the end of its life, and is costly to maintain and operate. We launched a project in 2011 to replace our existing customer system with the customer module consistent with our enterprise-wide system. The CIS Project commenced in 2011. The development will continue in 2012, and completion of system testing is expected to occur in 2013.

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, 2011 (Canadian dollars in millions)	**Total**	**2012**	**2013/2014**	**2015/2016**	**After 2016**
Contractual Obligations *(due by year):*					
Long-term debt – principal repayments	7,975	600	1,350	1,000	5,025
Long-term debt – interest payments	6,779	408	716	615	5,040
Inergi LP (Inergi) outsourcing agreement[1]	420	138	261	21	-
Operating lease commitments	54	9	15	10	20
Environmental and asset retirement obligations[2]	329	30	61	48	190
Total Contractual Obligations[6]	15,557	1,185	2,403	1,694	10,275
Other Commercial Commitments *(by year of expiry)*:					
Bank line[3]	1,250	-	1,250	-	-
Letters of credit[4]	125	125	-	-	-
Guarantees[4]	326	326	-	-	-
Pension[5]	164	152	12	-	-
Total Other Commercial Commitments	1,865	603	1,262	-	-

[1] On May 1, 2010, we extended our Master Services Agreement with Inergi for a further three-year period. The term of the agreement, which would otherwise 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 polychlorinated biphenyl (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 materials from our facilities and the decommissioning and removal of certain switching stations. The expenditure pattern reflects our planned work programs for the periods.

[3] As a backstop to our commercial paper program, we have a $1,250 million revolving standby credit facility with a syndicate of banks that matures in June 2014.

[4] We currently have outstanding bank letters of credit of $124 million relating to retirement compensation arrangements. The other $1 million included in letters of credit pertains to operating letters of credit. 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 2012 are based on an actuarial valuation filed in September 2011 and effective December 31, 2009. Our annual pension contributions for 2012 will be approximately $152 million based on the expected level of pensionable earnings. Contributions beyond 2012 will be based on an actuarial valuation effective no later than December 31, 2012 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2012 are not estimable at this time.

[6] In addition, our 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 is considered individually material, and the majority do not extend beyond December 31, 2012.

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 Consolidated Balance Sheet and Consolidated 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 OM&A expense on our Consolidated Statement of Operations or within our capital expenditures. Expenditures related to our environmental programs and asset retirement obligations are not charged to our results of operations, but are reflected on our Consolidated Balance Sheet and Consolidated 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 the 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 electricity load is expected to decline in 2012 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 0.8%, with the industrial sector slightly outperforming the 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 1.2% and 1.1%, respectively. On the whole, load is expected to decline by about 1.5%. A reduction in load, beyond the load forecast included in our approved revenue requirements, would negatively impact our financial results.

Effect of Interest Rates

Changes in interest rates will impact the calculation of the revenue requirements filed upon which our rates are based. The first component impacted by interest rates is our 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 ROE would reduce Hydro One Networks' transmission and distribution businesses' results of operations by approximately $18 million and $10 million, respectively. 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, general outline agreements, vendor alliances and we also 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 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 total of $1,500 million in liquidity facilities as of December 31, 2011, 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 2011, we continued issuing sufficient cost-effective debt financing through the MTN Program in the Canadian capital markets and we arranged sufficient available liquidity. Economic conditions were volatile in 2011 and we expect they will remain volatile in 2012.

Pension Plan

During 2011, the deferred pension asset reported on our Consolidated Balance Sheet increased by $6 million to $466 million. We contributed $153 million into our pension plan in 2011, including a partial wind-up payment of $4 million. We incurred $148 million in net periodic pension benefit cost. On an accounting basis, the 2010 unfunded benefit obligation of $297 million increased by $482 million to $779 million. The plan experienced positive returns of about 2.19% 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 Board of Directors annually reviews our company's risk tolerances and our risk profile. The Audit and Finance Committee of our Board of Directors annually reviews 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. In 2009, the Province required Hydro One, among other entities, 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., 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 businesses.

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 ROE 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 2010 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 then 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. Hydro One Networks' targets have been set at 214 MW and 1,130 GWh, and the targets for Hydro One Brampton Networks are set at 46 MW and 190 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 licenced distributors must comply with in relation to the CDM targets set out in their licences. This code also sets out the conditions and rules that licenced 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 our capital expenditures. We have substantial amounts of existing debt which mature between 2012 and 2015, including $600 million maturing in 2012 and $600 million maturing in 2013. We plan to incur capital expenditures of approximately $1.8 billion in each of 2012 and 2013. 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 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 approvals; receipt of OEB approvals which can include expropriation; and appropriate consultation processes with First Nations and Métis. Obtaining OEB and/or environmental assessment approvals and carrying out these processes may also be impacted by opposition to the proposed site of transmission investments which could 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. This could have a material 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, such as outage planning with the IESO and transmission-connected customers, funding approval by the OEB, and supply chain availability for equipment suppliers and consulting services. In addition, opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities.

Adjustments to accommodate these external dependencies have been made in our planning process, and we are focused on overcoming these challenges to execute our work programs. 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.

Workforce Demographic Risk

By the end of 2011, approximately 18% of our employees were eligible for retirement and by 2013 there could be up to 21% 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. We are therefore focused on earlier identification and more rapid development of staff who demonstrate management potential. Moreover, we must also continue to advance our technical 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 businesses.

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 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.

Under applicable regulations, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We record an asset retirement obligation for the present value of the estimated future expenditures. The estimates are based on an external, expert study of the current expenditures associated with removing such materials from our facilities.

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 IT Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex IT 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 mitigate this risk through various methods including the use of security event management tools on our power and business systems, by separating our power system network from our business system network, by performing scans of our systems for known cyber threats and by providing company-wide awareness training to our personnel. We also engaged the services of external experts to evaluate the security and privacy protection aspects of our smart meter program related to customer data. We perform vulnerability assessments on our critical cyber assets and we ensure security and privacy controls are incorporated into new IT capabilities. Although these security and system disaster recovery controls are in place, there can be no guarantee that there will not be system failures or security breaches. Any such 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 in respect of 2010 and $148 million in respect of 2011 to its pension plan to satisfy minimum funding requirements. A one-time additional payment of $48 million was made in December 2010 and an additional contribution of $3.8 million was also made in 2011 to complete the funding associated with a partial plan wind-up. Contributions beyond 2011 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 increases.

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 ROE would reduce our Transmission Business' net income by approximately $18 million and our Hydro One Networks' 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 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 have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff hired after November 2005 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, 2013 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 of Indians under the *Indian Act* (Canada). Currently, the OEFC holds legal title to these assets and we manage them until we have obtained necessary authorizations to complete the title transfer. To occupy reserve land, we must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, we must negotiate an agreement (in the form of a Memorandum of Understanding) with the band, OEFC and any First Nations individuals who have occupancy rights. The agreement includes provisions whereby the First Nations consent to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. It is difficult to predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required agreements from the Indian bands. However, we anticipate that the amount will exceed the $1,142,743 that we paid in 2011. OEFC will continue to hold these assets until we are able to negotiate agreements with the Indian bands and occupants. If we cannot reach satisfactory agreements and obtain federal permits, we may have to relocate these assets from the Indian reserve lands to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary 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, effectively renewing the arrangement until February 28, 2015. If the agreement with Inergi 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 the 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, which could have an adverse effect on our company.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our Consolidated 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 Consolidated Financial Statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2011 amounted to $1,088 million and principally relate to future income tax, environmental costs, and the pension variance account. We have also recorded regulatory liabilities amounting to $660 million as at December 31, 2011. These amounts pertain primarily to deferred pension, Rider 8, the external revenue variance account, retail settlement variance accounts and future income tax. 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 now 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% is 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 3.57% to 4.87%, depending on the appropriate rate for the period when the particular obligation was 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 in effect in the period when each obligation was 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; contamination levels of equipment with PCBs; and the timing of work. All factors used in deriving our environmental liabilities represent our best estimates based on our planned approach of meeting current legislative and regulatory requirements. These requirements 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 current 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 2011 were approximately \$152 million, \$148 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 Consolidated 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 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. On August 11, 2011, the Board approved a new target policy asset mix of 60% exposure to equities, 35% exposure to fixed income and 5% in alternative assets consisting of real estate and infrastructure. The implementation of this new policy asset mix will begin in 2012. 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 2011, the return on pension plan assets was lower than this long-term assumption but was higher than in 2010.

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, 2011 declined to 5.25% from 5.75% used at December 31, 2010 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 declined by approximately 40-50 basis points between December 31, 2010 and December 31, 2011. Based on the duration of the plan's liabilities, discount rates would be 5.25% 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, 2011 was 5.25%.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has decreased from the range of 2.25% to 2.50% per annum as at December 31, 2010 to approximately 2.00% per annum as at December 31, 2011. 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 reasonable to use 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, 2011.

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 $20 million per year and an increase in the year-end obligation of about $174 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 and intangible 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 part of the cost of fixed and intangible 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 2011 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 UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

Accounting Framework for External Reporting

We previously planned to adopt IFRS effective January 1, 2012 with comparative restatement of our 2011 results. In the absence of a definitive International Accounting Standards Board (IASB) plan to provide guidance on rate-regulated accounting, we began evaluating the option of adopting US GAAP in lieu of IFRS in the first quarter of 2011. On July 7, 2011, we filed our application with the 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 us to file our Consolidated Financial Statements based on IFRS starting with reporting periods commencing after January 1, 2012. Our application requested approval to instead adopt US GAAP, without becoming a Securities and Exchange Commission registrant, for our 2012, 2013 and 2014 fiscal years. This was approved by the OSC on July 21, 2011, and the requested exemptive relief was granted. In addition, a change to Ontario Regulation 395/11 was made during 2011 that requires us to prepare our Consolidated Financial Statements in accordance with US GAAP for financial years on or after January 1, 2012. Our Board of Directors has approved a resolution authorizing us to report under US GAAP.

Under US GAAP, our financial reporting will be more stable and comparable with our current Canadian GAAP results than it would have been under IFRS. The use of US GAAP will also facilitate benchmarking to other large North American utilities in terms of our results, as well as facilitate transmission cost comparisons for the OEB. Our March 31, 2012 Consolidated Financial Statements will be prepared based on US GAAP with one year of comparative restatement. Our opening US GAAP Consolidated Balance Sheet as at January 1, 2010 will be based on a retrospective application of US GAAP. As a result of this decision, our IFRS conversion project efforts have been reduced. However, our work will be managed in such a way that it can effectively be restarted if a future transition to IFRS is required.

In anticipation of OSC approval of our application, we initiated a US GAAP conversion project that consists of three phases: scoping and diagnostic; analysis; and implementation. The scoping and diagnostic phase of our project involved a high-level review of the major differences between existing Canadian and US GAAP. We completed this phase in the second quarter. We also substantially completed the second or analytical phase of our project in the second quarter. This phase involved assessment of the impacts of adopting US GAAP on our Consolidated Financial Statements, including measurement, classification, presentation and disclosure. The major differences identified to date include a change to the presentation of preferred shares on the balance sheet and adjustments related to accounting for employee future benefits costs. Our preferred shares, which are held entirely by the Province, will be classified as mezzanine equity under US GAAP. In addition, the net pension obligation at the end of the reporting period will be recognized on our Consolidated Balance Sheet with an offsetting regulatory asset. In accordance with OEB rate orders, pension costs are recorded under Canadian GAAP when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs will be recorded in the same way under US GAAP. Employee future benefits other than pension are, and will continue to be recorded on an accrual basis. There are minor differences between Canadian and US GAAP for certain employee future benefits costs. However, we do not expect any significant change to the net asset position on our Consolidated Balance Sheet. Nor do we expect significant impacts on our Consolidated Statement of Operations following the application of US GAAP to our employee future benefits costs.

We continue to assess and refine the impact that the conversion will have upon our disclosures.

Accounting Framework for Rate Setting

Consistent with our approval from the OSC to adopt US GAAP for external financial reporting and securities filings, on July 15, 2011, we filed a Motion to Vary the OEB's 2012 Transmission rate decision seeking approval to adopt US GAAP as the basis for regulatory accounting and rate setting in place of the OEB's approved modified IFRS basis. We also included a request to adopt US GAAP for our Hydro One Networks Distribution Business in this application. While the OEB denied our requests for procedural reasons, it initiated a specific proceeding to evaluate the use of US GAAP by our Transmission Business and to determine any required revisions to the approved 2012 revenue requirement. On November 23, 2011, the OEB issued its decision with reasons approving the use of US GAAP by our Transmission Business. In this decision, the OEB determined that we should make a separate application to request the use of US GAAP for our Distribution Business. On December 1, 2011 we submitted our application requesting that our Distribution Business be authorized to use US GAAP for rate setting effective January 1, 2012. A decision on our request to adopt US GAAP for our Distribution Business is anticipated in the first quarter of 2012. On December 16, 2011, we made a similar request to the OEB in respect of our Remote Communities business. We did not make a request to adopt US GAAP on behalf of our Hydro One Brampton Networks subsidiary and, as a result, it will have its rates set based on modified IFRS once its current IRM period is complete.

Debt Covenants

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. As part of our US GAAP transition, we analyzed the impact of potential accounting changes on our debt covenants. Based on the work performed in phases one and two of our project, after conversion to US GAAP we expect to remain in compliance with these covenants. We also amended our bond indentures to allow us to use US GAAP for external reporting purposes.

Internal Control over Financial Reporting and Disclosure Controls and Procedures

We have assessed the impact of conversion from Canadian GAAP to US GAAP on our internal controls over financial reporting and on our disclosure controls and procedures. We do not anticipate any changes to existing controls or a need for additional controls as a result of conversion.

Financial Reporting Expertise

Given the similarities between US GAAP and current Canadian GAAP, our US GAAP training efforts are focused on specific areas of difference between the two accounting frameworks and these efforts are initially being targeted to specific staff, senior executive management and the Audit and Finance Committee of our Board of Directors. In the first quarter of 2012, additional formal training will be provided to other finance and operational staff who are not directly involved in our conversion project. This training will concentrate on communicating the key differences between Canadian and US GAAP at a level of detail that is appropriate to meet their respective needs.

IT Systems

We have completed a preliminary assessment of the impacts of converting to US GAAP on our IT systems. Our recently implemented SAP enterprise systems allow for flexibility in the application of accounting policies and, given the similarities between Canadian and US GAAP, we anticipate that any required IT system changes to accommodate US GAAP will be comparatively minor. Our systems have been designed to be sufficiently flexible to allow the future adoption of IFRS should this be required.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING (ICFR)

Our Supply Chain Enhancement Project to develop an operating framework that outlines the strategy and objectives of our supply chain was implemented in the second quarter of 2011. The resulting new processes have been reviewed to assess the impact on the control environment. Process documents have been updated and controls have been tested for design and operating effectiveness.

In an effort to optimize our customer service operations, we have initiated our CIS Project. The new system will replace two legacy applications currently in use to provide billing, customer contact, field services, settlements and customer choice administration to our distribution customers and key constituents. The CIS Project is currently in the final stages of the design phase which will be followed by the build phase. During the build phase, CIS process documentation will continue to be reviewed and analyzed to ensure that key risks remain adequately addressed by our internal controls. Any new controls will be documented and tested as part of our ongoing certification process.

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, 2011, 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, 2011. 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 Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of our company's ICFR, our Certifying Officers concluded that our ICFR was effective as at December 31, 2011.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2009, 2010 and 2011. 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)*	**2011**	**2010**	**2009**
Revenues	5,471	5,124	4,744
Net income	641	591	470
Basic and fully diluted earnings per common share	6,228	5,727	4,528

Consolidated Balance Sheets *Year ended December 31 (Canadian dollars in millions, except cash dividends per share)*	**2011**	**2010**	**2009**
Total assets	18,368	17,322	15,635
Total long-term debt	7,999	7,778	6,881
Cash dividends per common share	1,500	100	1,700
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, continuous innovation, reliability, protection of the environment, employee engagement, shareholder value and productivity and cost-effectiveness. 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 meeting the unique needs of our diverse customer base through dialogue to understand their needs. We will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers more capability to manage their own costs. The ADS is a key element in our investment in innovation. We will provide a robust and reliable provincial grid that accommodates the province's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. We will support the connection of renewable energy sources through the incorporation of ADS technology into our distribution system. We will continue to focus on reducing our carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use. We will also continue to strive for productivity through efficiency and effective management of costs, which is key to achieving value for our customers and our shareholder.

Following the release of the LTEP late in 2010, the Province issued a supply mix directive on February 17, 2011 that will form the basis for a new IPSP. The LTEP, and the proposed IPSP, support the continued procurement of new, cleaner generation consistent with the energy strategies set out in the GEA. Our transmission license was amended during the year to require us to undertake three of five priority projects listed in the LTEP as well as up to 15 transmission station upgrades to accommodate small-scale renewable generation.

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. The reliability of our current and future system is dependent on addressing aging infrastructure, making required asset replacements and ensuring continuous maintenance programs. 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. We remain focused on balancing our expenditures associated with the LTEP, the costs and challenges of connecting DG, the execution of our sustainment programs and the impacts of rates on our customers.

In late 2010, the OEB approved our 2011 and 2012 transmission rates, with a revenue requirement for 2012 of $1,658 million, reflecting the adoption of modified IFRS. On November 23, 2011, the OEB granted our request to adopt US GAAP for our Transmission Business effective January 1, 2012 and on December 20, 2011 approved a revised 2012 revenue requirement of $1,418 million. The approved revenue requirement will support aging critical infrastructure, area supply projects and the Province's policy objectives.

A request was submitted on December 1, 2011 to the OEB to grant Hydro One Networks' Distribution Business approval of the use of US GAAP for rate-setting, regulatory accounting and reporting purposes effective January 1, 2012. Once approved by the OEB, the initiative to move our financial reporting to a US GAAP basis will have a beneficial impact by avoiding an increase in customer rates related to capitalization policies allowed under modified IFRS.

A transmission cost-of-service rate application is planned for 2013 and 2014 with a proposed regulated return on equity based on the application of the OEB's cost-of-capital report. We are currently reviewing our options for our Distribution Business.

The actual timing and expenditures in our business 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 our 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 *Corporate Knights* magazine. We have also partnered with various communities and First Nations and Métis groups along the Bruce to Milton corridor for a biodiversity initiative that will enhance the natural environment in the local communities and seek to improve local biodiversity.

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 apprenticeship program and our association with universities, colleges and our unions, as well as skills development and retention. Effective use of human resources and ensuring correct skills will be critical to attaining the balance between meeting the asset needs and mitigating rate impact on the customer. Although the work program is assumed to grow moderately over the 2012 and 2013 years, no increase in regular staff numbers is anticipated over that period. With regard to materials, we are seeing a need for 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. We have considered and will continue to consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis. Our plan does not include funding for LDC acquisitions or assume any disposition of our service territory. These opportunities will be managed as they arise. Our plan also does not incorporate any projects related to competitive transmission. However, as leaders in the sector, we plan to bid on key projects.

We will continue to increase enterprise value through productivity improvements and cost-effectiveness driven by technology. Over the last three years, we have replaced most of our core IT systems with an enterprise-wide IT 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 an ADS, including energy efficiency, demand response and distributed-resources technologies.

As part of our critical role as an enabler, we will continue to take a leadership role in the development and maintenance of the transmission and distribution grids.

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, including the consultation process; statements about smart meters and the ADS including their capabilities, installation and areas of implementation; 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; statements about the FIT review; expectations regarding the OEB's renewed regulatory framework for electricity distributors and transmitters including the anticipated outcome; statements about outstanding legal proceedings; statements regarding the transition to TOU 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; statements regarding our ongoing and planned projects and/or initiatives including the expected approval process, and the expected results of these projects and/or initiatives and their completion dates; expectations regarding our participation in future projects; expectations regarding the recoverability of liabilities and assets; 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; expectations regarding our pursuance of OEB-approved 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 counter-parties; 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; statements regarding provincial ownership of our transmission corridors; statements about critical accounting estimates; statements about US GAAP and our adoption of US GAAP; 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; 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;
- results arising from the FIT review and the IPSP consultation process;
- 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, rates, and the recoverability of costs, liabilities and assets, 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 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 is terminated; and
- the impact of the ownership by the Province of lands underlying our transmission system.

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, 2012. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
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, 2012.

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). The effectiveness of these internal controls is evaluated and findings are reported 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 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:

L Formusa

Laura Formusa
President and Chief Executive Officer

Sandy Struthers
Executive Vice-President and Chief Financial Officer

HYDRO ONE INC.
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, 2011 and December 31, 2010, the consolidated statements of operations and comprehensive income, retained earnings, accumulated other comprehensive loss, 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 consolidated financial position of Hydro One Inc. as at December 31, 2011 and December 31, 2010, and the results of its consolidated operations and its consolidated 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, 2012

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (Canadian dollars in millions, except per share amounts)	**2011**	**2010**
Revenues		
Transmission *(Note 16)*	1,389	1,307
Distribution *(Note 16)*	4,019	3,754
Other	63	63
	5,471	5,124
Costs		
Purchased power *(Note 16)*	2,628	2,474
Operation, maintenance and administration *(Note 16)*	1,092	1,078
Depreciation and amortization *(Note 3)*	616	583
	4,336	4,135
Income before financing charges and provision for payments in lieu of corporate income taxes	1,135	989
Financing charges *(Note 4)*	344	342
Income before provision for payments in lieu of corporate income taxes	791	647
Provision for payments in lieu of corporate income taxes *(Notes 5 and 16)*	150	56
Net income	641	591
Other comprehensive income	-	-
Comprehensive income	641	591
Basic and fully diluted earnings per common share *(Canadian dollars) (Note 15)*	6,228	5,727

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Retained earnings, January 1	2,354	1,791
Net income	641	591
Dividends *(Note 15)*	(168)	(28)
Retained earnings, December 31	2,827	2,354

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Accumulated other comprehensive loss, January 1	(10)	(10)
Other comprehensive loss	-	-
Accumulated other comprehensive loss, December 31	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2011**	**2010**
Assets		
Current assets:		
Cash	-	33
Short-term investments	228	139
Accounts receivable (net of allowance for doubtful accounts - $18 million; 2010 - $25 million) *(Note 16)*	961	911
Regulatory assets *(Note 8)*	24	42
Materials and supplies	25	21
Future income tax assets *(Note 5)*	19	35
Other	20	8
	1,277	1,189
Fixed assets *(Note 6)*:		
Fixed assets in service	21,008	19,767
Less: Accumulated depreciation	7,679	7,247
	13,329	12,520
Construction in progress	1,436	1,394
Future use land, components and spares	138	139
	14,903	14,053
Other long-term assets:		
Regulatory assets *(Note 8)*	1,064	1,013
Deferred pension asset *(Note 12)*	466	460
Long-term investment	250	249
Intangible assets (net of accumulated amortization) *(Note 7)*	224	197
Goodwill	133	133
Future income tax assets *(Note 5)*	17	19
Other	34	9
	2,188	2,080
Total assets	18,368	17,322

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2011**	**2010**
Liabilities		
Current liabilities:		
Bank indebtedness	39	-
Accounts payable and accrued charges *(Notes 13 and 16)*	1,071	884
Regulatory liabilities *(Note 8)*	25	72
Accrued interest	85	84
Long-term debt payable within one year *(Note 9)*	600	500
	1,820	1,540
Long-term debt *(Note 9)*	7,399	7,278
Other long-term liabilities:		
Employee future benefits other than pension *(Note 12)*	1,040	980
Regulatory liabilities *(Note 8)*	635	540
Future income tax liabilities *(Note 5)*	758	693
Environmental liabilities *(Note 13)*	235	287
Asset retirement obligations *(Note 14)*	15	11
Long-term accounts payable and other liabilities	12	12
	2,695	2,523
Total liabilities	11,914	11,341
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	2,827	2,354
Accumulated other comprehensive loss	(10)	(10)
Total shareholder's equity	6,454	5,981
Total liabilities and shareholder's equity	18,368	17,322

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

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Operating activities		
Net income	641	591
Environmental expenditures	(16)	(17)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	550	526
Regulatory asset and liability accounts	47	(10)
Gain on interest rate swap agreements	(12)	(17)
Future income taxes	(12)	(8)
Asset retirement obligation	4	4
Other	9	1
	1,211	1,070
Changes in non-cash balances related to operations *(Note 17)*	196	94
Net cash from operating activities	1,407	1,164
Financing activities		
Long-term debt issued	700	1,500
Long-term debt retired	(500)	(600)
Short-term notes payable	-	(55)
Dividends paid	(168)	(28)
Other	(4)	-
Net cash from financing activities	28	817
Investing activities		
Capital expenditures		
Fixed assets	(1,371)	(1,557)
Intangible assets	(76)	(13)
	(1,447)	(1,570)
Long-term investments	-	(250)
Other assets	29	37
Net cash used in investing activities	(1,418)	(1,783)
Net change in cash and cash equivalents	17	198
Cash and cash equivalents, January 1	172	(26)
Cash and cash equivalents, December 31 *(Note 17)*	189	172

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton 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.

Rate-setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB.

Transmission

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 returns on equity of 8.53% and 9.35% for 2009 and 2010, respectively. On May 28, 2009, the OEB issued its decision with reasons 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 with reasons effective January 1, 2011, which resulted in approved revenue requirements of $1,346 million for 2011 and $1,658 million for 2012. The approved 2012 revenue requirement was higher than that applied for, reflecting OEB direction to Hydro One to adopt a modified International Financial Reporting Standards (IFRS) cost capitalization policy. This adjustment was subsequently reversed by the OEB when it approved the use of United States (US) Generally Accepted Accounting Principles (GAAP) for rate-setting purposes beginning January 1, 2012.

Distribution

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 a previous 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 into service beyond a prescribed threshold. On May 13, 2009, the OEB released its decision with reasons approving the basic IRM increase and a rate adder 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.

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 with reasons 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 regulatory 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 7, 2008, Hydro One Brampton filed an application for 2009 rates on the basis of the OEB's second-generation IRM policy. On March 13, 2009, the OEB released it decision with reasons. The revised rates, including an adder of $1 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 Hydro One Brampton's 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 June 30, 2010, Hydro One Brampton submitted a 2011 cost-of-service application, which was subsequently adjusted on September 2, 2010 to reflect the deferral of the adoption of modified IFRS until January 1, 2012. The updated submission was filed on November 8, 2010 and requested OEB approval for a revenue requirement of approximately $63 million. On April 4, 2011, the OEB issued a decision with reasons that reduced the requested revenue requirement. This reduction included the impact of reductions to operation, maintenance and administration costs. The revised rates were approved with an effective date of January 1, 2011 and an implementation date of May 1, 2011. Included in the rates is an adder of $1.52 per month per metered customer for smart meters and approval of a GEA funding adder of $0.02 per month per metered customer.

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. The increase reflects the standard inflationary adjustments incorporated in the third-generation IRM applications. On April 14, 2010, the OEB issued a decision with reasons regarding this rate application, approving revised rates with an effective date and implementation date of May 1, 2010.

On October 15, 2010, Hydro One Remote Communities filed an application for 2011 distribution rates 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. On March 28, 2011, the OEB issued its decision with reasons approving the application. The revised rates were approved with an effective date and implementation date of May 1, 2011.

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, 2011 amounted to $544 million (2010 - $493 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.

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 Consolidated 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 Consolidated 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 tax liabilities and assets that are expected to be recovered from or repaid to the customers in the rate-setting 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 the 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 comprise materials, purchased software, labour and consulting, engineering, overheads and the OEB-approved allowance for funds used during construction applicable to capital activities within regulated businesses, or interest applicable to capital activities within unregulated 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 (2011 - 4.20%; 2010 - 4.34%).

Depreciation and Amortization

The capital costs of fixed 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%	8%

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 lives. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of fixed and intangible 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.

Financial Instruments

Recognition and Measurement

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 other comprehensive income (OCI) until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Assets / Liabilities	Classification	Measurement
Cash	Held-for-trading	Fair value
Accounts receivable	Loans and receivables	Amortized cost
Short-term investments	Held-to-maturity / Held-for-trading	Amortized cost / fair value
Long-term investment	Held-to-maturity	Amortized cost
Bank indebtedness	Other liabilities	Amortized cost
Accounts payable	Other liabilities	Amortized cost
Short-term notes payable	Other liabilities	Amortized cost
Long-term debt (unless otherwise specified)	Other liabilities	Amortized cost
Fixed-to-floating interest-rate swaps	Not classified	Fair value
Medium-Term Note (MTN) Series 14 Note	Not classified	Fair value
$500 million of MTN Series 19 Note	Not classified	Fair value
$250 million of MTN Series 21 Note	Not classified	Fair value
Floating-to-fixed interest-rate swaps	Held-for-trading	Fair value

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.

Certain tranches of long-term debt are designated as part of a hedging relationship, as in the case of the MTN Series 14 Note, $500 million of the MTN Series 19 Note and $250 million of the MTN Series 21 Note. These long-term debt, and related hedging instruments, are not classified.

All financial instrument transactions are recorded at trade date.

Discounts and Premiums on Debt

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

Transaction Costs

Transaction costs for financial assets and liabilities that are classified as other than held-for-trading are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method.

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. The Company does not have any significant embedded derivatives in contracts that require separate accounting and disclosure.

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.

Comprehensive Income

Comprehensive income is comprised of the Company's net income and 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 Instrument Disclosures

All financial instruments measured at fair value are categorized into one of the three levels of hierarchy. Each level is based on the transparency of the inputs used to measure the fair values of assets and liabilities:

Level 1 – inputs are unadjusted quoted prices of identical instruments in an active market;
Level 2 – inputs do not have quoted prices but are observable for the asset or liability, either directly or indirectly; and
Level 3 – inputs that are not based on observable market data.

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 and intangible 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 (PCB) 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. The asset retirement obligations recorded to date are primarily related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of the Company's facilities and the decommissioning of certain switching stations.

Use of Estimates

The preparation of Consolidated 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 Consolidated 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

US GAAP

The Company previously anticipated it would apply IFRS to its Consolidated Financial Statements for fiscal periods beginning on or after January 1, 2012, with comparative restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011. 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 2011. On July 7, 2011, the Company filed an application with the 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 Consolidated Financial Statements based on IFRS starting with reporting periods commencing after January 1, 2012. The Company'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 the Company'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's March 31, 2012 Consolidated Financial Statements will be prepared based on US GAAP with one year of comparative restatement. The Company's opening US GAAP Consolidated Balance Sheet as at January 1, 2010 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 Consolidated Financial Statements will be assessed as part of the Company's US GAAP conversion project.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Depreciation of fixed assets in service	485	456
Amortization of intangible assets	45	43
Fixed asset removal costs	66	57
Amortization of regulatory and other assets	20	27
	616	583

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Interest on long-term debt payable	412	409
Amortization of debt issuance costs	3	3
Other	5	7
Less: Interest capitalized on construction and development in progress	(58)	(54)
Gain on interest-rate swap agreements	(12)	(17)
Net amortization of premiums	(3)	(3)
Interest earned on investments	(3)	(3)
	344	342

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)	**2011**	**2010**
Income before provision for PILs	791	647
Federal and Ontario statutory income tax rate	28.25%	31.00%
Provision for PILs at statutory rate	223	201
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(34)	(82)
Pension contributions in excess of pension expense	(17)	(18)
Overheads capitalized for accounting but deducted for tax purposes	(12)	(13)
Interest capitalized for accounting but deducted for tax purposes	(16)	(17)
Employee future benefits other than pension expense in excess of cash payments	5	3
Environmental expenditures	(4)	(5)
Other	3	(15)
Net temporary differences	(75)	(147)
Net permanent differences	2	2
Total income tax provision for PILs	150	56
Current income tax provision for PILs	162	64
Future income tax provision for PILs	(12)	(8)
Total income tax provision for PILs	150	56
Effective income tax rate	18.96%	8.66%

The provision for payments in lieu of current income taxes of $162 million represents the amount payable to the OEFC with respect to current year earnings. The outstanding balance due to the OEFC at December 31, 2011 is $85 million (2010 - $17 million).

The payments in lieu of future income taxes recoverable of $12 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 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)	**2011**	**2010**
Future income tax assets		
Depreciation and amortization in excess of capital cost allowance	6	9
Employee future benefits other than pension expense in excess of cash payments	5	5
Environmental expenditures	5	3
Other	1	5
Total future income tax assets	17	22
Less: current portion	-	3
	17	19

December 31 (Canadian dollars in millions)	**2011**	**2010**
Future income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,106)	(1,004)
Employee future benefits other than pension expense in excess of cash payments	356	337
Environmental expenditures	61	76
Transmission and Distribution amounts received but not recognized for accounting purposes	(46)	(69)
Goodwill	(18)	(17)
Retail settlement variance accounts	10	5
Other	5	11
Total future income tax liabilities	(739)	(661)
Less: current portion	19	32
	(758)	(693)

As at December 31, 2011, payments in lieu of future income tax assets of $608 thousand (2010 - $574 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
2011				
Transmission	10,906	3,810	1,079	8,175
Distribution	7,596	2,706	253	5,143
Communication	919	468	43	494
Administration and service	1,232	607	61	686
Easements	493	88	-	405
	21,146	7,679	1,436	14,903
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	25	560
Easements	491	85	-	406
	19,906	7,247	1,394	14,053

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 $57 million in 2011 (2010 - $54 million).

7. INTANGIBLE ASSETS

December 31 (Canadian dollars in millions)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2011				
Computer applications software	427	254	49	222
Other assets	5	3	-	2
	432	257	49	224
2010				
Computer applications software	395	209	9	195
Other assets	5	3	-	2
	400	212	9	197

Financing costs are capitalized on intangible assets under development, including allowance for funds used during development of regulated assets, and were $1 million in 2011 (2010 - $nil).

8. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (Canadian dollars in millions)	2011	2010
Regulatory assets:		
Regulatory future income tax asset	763	674
Environmental	257	309
Pension cost variance account	42	27
Rider 2 (Regulatory asset recovery account II)	11	11
Long-term project development cost account	5	7
Rural and remote rate protection variance account	-	7
Rider 4 (Revenue recovery account)	-	5
Other	10	15
Total regulatory assets	1,088	1,055
Less: current portion	24	42
	1,064	1,013

	2011	2010
Regulatory liabilities:		
Deferred pension	466	460
Rider 8	41	9
External revenue variance account	39	29
Retail settlement variance accounts	39	22
Regulatory future income tax liability	25	30
Rider 3 (Regulatory liability refund account)	9	19
PST savings deferral account	8	4
Rural and remote rate protection variance account	8	-
Hydro One Brampton rider	2	6
Rider 6	-	19
Other	23	14
Total regulatory liabilities	660	612
Less: current portion	25	72
	635	540

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 Consolidated 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-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 established for taxes to be recovered through future rates. As a result, the provision for PILs would have been higher by approximately $70 million (2010 - $104 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 2011, this regulatory asset decreased by $55 million (2010 - decreased by $15 million) to reflect related changes in the Company's PCB liability and increased by $5 million (2010 - decreased by $1 million) for changes 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 $50 million (2010 - $16 million). In addition, amortization expense in 2011 would have been lower by $16 million (2010 - $17 million) and financing charges would have been higher by $14 million (2010 - $15 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 difference between 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 $14 million in 2011 (2010 - $20 million).

Rider 2 or Regulatory Asset Recovery Account 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 regulatory account balances sought by Hydro One. Rider 2 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 2011 would have remained unchanged (2010 - lower by $8 million). In addition, related financing charges would have remained the same in both years.

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 then Minister of Energy and Infrastructure. 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 lower by $2 million (2010 - higher by $5 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.

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 $3 million (2010 - $22 million).

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.

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, 2011 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 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.

Rider 3 or 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.

PST savings deferral account

The amounts recognized in this regulatory account reflect the impact on the Company from the implementation of an HST sales tax regime on July 1, 2010. The variance recognized is the amount approved in the revenue requirement relating to the previous Provincial Sales Tax (PST) regime. The PST savings are refundable to ratepayers in future years.

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 through a rate rider over a two-year period from May 1, 2010 to April 30, 2012.

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.

9. DEBT

December 31 (Canadian dollars in millions)	**2011**	**2010**
Long-term debt:		
4.08% notes due 2011[1]	-	250
6.40% notes due 2011	-	250
5.77% notes due 2012	600	600
5.00% notes due 2013	600	600
3.13% notes due 2014[1]	750	750
2.95% notes due 2015[1]	500	250
Floating-rate notes due 2015	50	-
4.64% notes due 2016	450	450
5.18% notes due 2017	600	600
4.40% notes due 2020	300	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	500
4.39% notes due 2041	300	-
6.59% notes due 2043	315	315
5.00% notes due 2046	325	325
4.00% notes due 2051	100	-
	7,975	7,775
Add: Unrealized marked-to-market loss[1]	33	8
Less: Long-term debt payable within one year	(600)	(500)
Net unamortized premiums	23	27
Unamortized debt issuance costs	(32)	(32)
Long-term debt	7,399	7,278

[1] The unrealized marked-to-market loss relates to the MTN Series 14 Note which matured on March 3, 2011; $500 million of the MTN Series 19 Note which will mature on November 14, 2014 and $250 million of the MTN Series 21 Note issued in January 2011 which will mature on September 11, 2015 which are all accounted for as fair value hedges. The unrealized marked-to-market loss is offset by a $33 million (2010 - $8 million) unrealized marked-to-market 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. There was no short-term debt outstanding as of December 31, 2011 and December 31, 2010.

Hydro One has a $1,250 million committed and unused revolving standby credit facility with a syndicate of banks maturing in June 2014. 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 as an alternative source of liquidity.

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 $2,600 million was remaining and available as at December 31, 2011.

On August 2, 2011, the Company entered into two forward-rate agreements to lock in two interest-rate resets on the floating rate it pays on $50 million and $115 million of floating-rate debt with settlement dates of October 24 and November 21, 2011, respectively. The cash settlements on the forward rate agreements that settled on October 24 and November 21 were insignificant.

On November 16, 2011, the Company entered into two floating-to-fixed interest-rate swaps for $250 million each to lock in the floating rate it pays on (i) a $250 million fixed-to-floating interest-rate swap from December 12, 2011 to December 11, 2012 and (ii) a $250 million fixed-to-floating interest-rate swap from February 21, 2012 to February 19, 2013. On the same date it also entered into a floating-to-fixed interest-rate swap for $50 million to lock in the floating rate it pays on $50 million floating-rate notes from January 24, 2012 to January 24, 2013. The Company designated these swaps as fair value hedges of interest-rate risk. As such, changes in fair value are recognized in the Consolidated Statement of Operations for the period.

On December 22, 2011, the Company issued $100 million 4.00% notes under its MTN program with a maturity date of December 22, 2051.

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, 2011 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	-	-	-	961	-
Short-term investments	-	-	228	-	-
Long-term investment	-	-	250	-	-
Other assets	33	-	-	2	-
Financial Liabilities					
Bank indebtedness	-	-	-	-	39
Accounts payable and accrued charges[1]	-	-	-	-	976
Long-term debt	-	783	-	-	7,216

[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)	**2011**		**2010**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	7,975	9,389	7,775	8,555

[1] The carrying value of long-term debt represents the par value of the notes and debentures. The fair value of long-term debt represents the market value of the notes and debentures, other than the MTN Series 14 Note, $500 million of the MTN Series 19 Note and $250 million of the MTN Series 21 Note, which are designated as part of hedging relationships and are therefore marked-to-market using the yield in the swap market for the related swaps.

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 transmission and distribution 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 $18 million and its Hydro One Networks' 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, 2011, 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, 2011, there were no significant balances of accounts receivable due from any single customer.

In the year, the Company's provision for bad debts decreased to $18 million (2010 - $25 million). 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 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, 2011.

Derivative financial instruments result in credit risk exposure of the counter-party involved for there is a risk of default by the counter-party of its obligation under these derivative instruments. As at December 31, 2011, the derivative instruments executed by Hydro One include: (a) 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; (b) two $125 million fixed-to-floating interest-rate swap agreements to convert $250 million of the 2.95% coupon note maturing September 11, 2015 into a three-month variable rate debt; (c) two $250 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company will pay for the next 12 months on the above fixed-to-floating interest-rate swaps; and (d) a $50 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company will pay for the next 12 months on $50 million floating-rate debt. The counter-party credit risk exposure on the fair value of these interest-rate swap contracts is $36 million as at December 31, 2011 (2010 - $11 million).

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, the Company's revolving credit facility and through the Company's 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, 2014 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 Hydro One's normal operating requirements.

As at December 31, 2011, accounts payable and accrued charges in the amount of $976 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 long-term debt amount to $408 million.

As at December 31, 2011, Hydro One has issued long-term debt in the amount of $7,975 million and the Company is required to make interest payments in the amount of $6,779 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	408	5.8
2 years	600	373	5.0
3 years	750	343	3.1
4 years	550	320	2.8
5 years	450	295	4.6
	2,950	1,739	4.2
6 – 10 years	900	1,277	4.9
Over 10 years	4,125	3,763	5.8
	7,975	6,779	5.1

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 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, 2011 and December 31, 2010 was as follows:

(Canadian dollars in millions)	**2011**	**2010**
Long-term debt payable within one year	600	500
Less: cash and cash equivalents	189	172
	411	328
Long-term debt	7,399	7,278
Preferred Shares	323	323
Common Shares	3,314	3,314
Retained Earnings	2,827	2,354
	6,464	5,991
Total Capital	14,274	13,597

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," "bank indebtedness" and "short-term investments."

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, 2011, 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, 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, 2011 and 2010 was as follows:

	% of Plan Assets	
December 31	**2011**	**2010**
Equity securities	59.4	63.5
Debt securities	37.1	30.7
Other[1]	3.5	5.8
	100.0	100.0

[1] Composed of cash and cash investments.

Supplementary Information

The Hydro One pension plan holds $27 million of Hydro One Inc. corporate bonds (2010 - $14 million) and holds debt securities of the Province of $214 million at December 31, 2011 (2010 - $70 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 $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). The Company made an additional payment of $48 million in December 2010 and an additional payment related to a partial plan wind-up in 2011 of $4 million. 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 2011, 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 $195 million (2010 - $233 million).

	Pension		Employee Future Benefits other than Pension	
Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**	**2011**	**2010**
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	4,996	4,566	1,178	1,004
Current service cost	108	94	30	24
Interest cost	286	294	68	65
Reciprocal transfers	4	4	-	-
Benefits paid	(289)	(262)	(42)	(42)
Net actuarial loss (gain)	356	300	(28)	127
Accrued benefit obligation, December 31	5,461	4,996	1,206	1,178
Change in plan assets				
Fair value of plan assets, January 1	4,699	4,336	-	-
Actual return on plan assets	102	421	-	-
Reciprocal transfers	4	4	-	-
Benefits paid	(289)	(262)	-	-
Employer's contributions[1]	153	191	-	-
Employees' contributions	27	24	-	-
Administrative expenses	(14)	(15)	-	-
Fair value of plan assets, December 31	4,682	4,699	-	-
Funded status				
Unfunded benefit obligation	(779)	(297)	(1,206)	(1,178)
Unamortized net actuarial losses	1,238	746	115	144
Unamortized past service costs	7	11	8	11
Deferred pension asset (accrued benefit liability)	466	460	(1,083)	(1,023)
Less: current portion	-	-	43	43
Deferred pension asset (long-term liability)	466	460	(1,040)	(980)

[1] In January 2012, the Company made a contribution of $12 million in respect of 2011 (2011 - $13 million in respect of 2010).

Year ended December 31 (Canadian dollars in millions)	Pension 2011	Pension 2010	Employee Future Benefits Other Than Pension 2011	Employee Future Benefits Other Than Pension 2010
Components of net periodic benefit cost				
Current service cost, net of employee contributions	81	70	30	24
Interest cost	286	294	68	65
Actual return on plan assets net of expenses	(88)	(406)	-	-
Actuarial loss (gain)	356	300	(28)	127
Other	-	(1)	-	-
Costs arising in the period	635	257	70	216
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	(202)	129	-	-
Actuarial (gain) loss	(289)	(236)	30	(134)
Plan amendments	4	4	3	4
Net periodic benefit cost	148	154	103	86
Charged to results of operations[2]	93	134	61	51
Effect of a 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	174	185
Service cost and interest cost	-	-	20	15
Effect of a 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	(138)	(146)
Service cost and interest cost	-	-	(14)	(12)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	6.25%	6.50%	-	-
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%
Average remaining service life of employees *(years)*	11	10	11	11
Rate of increase in health care cost trend[3]	-	-	4.86%	4.81%
For accrued benefit obligation, December 31:				
Weighted average discount rate	5.25%	5.75%	5.25%	5.75%
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]	-	-	4.51%	4.86%

[2] The Company follows the cash basis of accounting. During 2011, pension costs of $153 million (2010 - $191 million) were attributed to labour, of which $93 million (2010 - $134 million) was charged to operations and $60 million (2010 - $57 million) was capitalized as part of the cost of fixed assets.

[3] 8.31% in 2011 grading down to 4.86% per annum in and after 2029 (2010 - 8.57% in 2010 grading down to 4.81% per annum in and after 2029).

[4] 8.11% in 2012 grading down to 4.51% per annum in and after 2031 (2010 - 8.31% in 2011 grading down to 4.86% per annum in and after 2029).

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	PCB	LAR	Total
2011			
Opening balance, January 1	251	58	309
Interest accretion	12	2	14
Expenditures	(9)	(7)	(16)
Revaluation adjustment	(55)	5	(50)
Ending balance, December 31	199	58	257
Less: current portion	(13)	(9)	(22)
	186	49	235
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

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2011 and in total thereafter are as follows: 2012 - $22 million; 2013 - $24 million; 2014 - $36 million; 2015 - $25 million; 2016 - $23 million; and thereafter - $173 million. Of the total estimated future expenditures, $242 million relate to PCBs (2010 - $308 million) and $61 million to LAR (2010 - $61 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.

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 3.57% 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 $242 million (2010 - $308 million). These expenditures are expected to be incurred over the period from 2012 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 $55 million (2010 - $15 million) compared to the September 30 balance for the respective year.

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 increased its December 31, 2011 liability by approximately $5 million (2010 - decreased by $1 million) compared to the September 30 balance for the respective year. 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 its 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. In 2010, 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 current present value of the estimated future expenditures is $7 million. The amount of interest recorded is nominal and there have been no expenditures associated with this obligation.

In 2011, Hydro One recorded a $4 million asset retirement obligation related to the future decommissioning and removal of one of its switching stations. Including the obligation recorded in respect of another switching station in 2010, the present value of the estimated future expenditures to discharge these obligations is about $8 million. Interest recorded on this amount in the year was nominal and there have been no expenditures associated with these obligations to date.

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 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 2011, preferred dividends in the amount of $18 million (2010 - $18 million) and common dividends in the amount of $150 million (2010 - $10 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 the IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2011 includes $1,366 million (2010 - $1,277 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2011 includes $127 million (2010 - $127 million) related to this program. Hydro One also received revenue from the IESO related to the supply of electricity to remote northern communities. Distribution revenue for 2011 includes $28 million (2010 - $28 million) related to these services.

In 2011, Hydro One purchased power in the amount of $2,401 million (2010 - $2,361 million) from the IESO-administered electricity market, $16 million (2010 - $19 million) from OPG and $10 million (2010 - $13 million) from the 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 2011, Hydro One incurred $11 million (2010 - $11 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations of Ontario Hydro. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $11 million (2010 - $14 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 2011 and 2010.

The OPA funds substantially all of the Company's Conservation Demand Management (CDM) programs. The funding includes program costs, incentives, management fees and bonuses. In 2011, Hydro One received $39 million from the OPA in respect of the CDM programs (2010 - $36 million).

The provision for PILs, property taxes and capital taxes were 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)	**2011**	**2010**
Accounts receivable	143	111
Accounts payable and accrued charges	(344)	(283)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $209 million (2010 - $222 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)	**2011**	**2010**
Accounts receivable increase	(38)	(51)
Materials and supplies increase	(4)	-
Accounts payable and accrued charges increase	188	87
Accrued interest increase	1	10
Long-term accounts payable and other liabilities decrease	-	(3)
Employee future benefits other than pension increase	60	40
Other	(11)	11
	196	94

Supplementary information:		
Interest paid	413	409
Payments in lieu of corporate income taxes	80	48

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.

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, it anticipates having to pay more than the $1,142,743 that it paid to these Indian bands and bodies in 2011. If Hydro One cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's net income if it is not able to recover them in future rate orders.

19. COMMITMENTS

Agreement with Inergi LP (Inergi)

Effective March 1, 2002, 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 billings for these services have ranged between $93 million and $130 million per year and are 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, 2011, and in total thereafter are as follows: 2012 - $138 million; 2013 - $133 million; 2014 - $128 million; 2015 - $21 million; 2016 and thereafter - $nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2011, 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, 2011 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, 2011, Hydro One had bank letters of credit of $124 million (2010 - $113 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, 2011, and in total thereafter are as follows: 2012 - $8 million; 2013 - $8 million; 2014 - $8 million; 2015 - $3 million; 2016 - $7 million; and thereafter - $20 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**
2011				
Segment profit				
Revenues	1,389	4,019	63	5,471
Purchased power	-	2,628	-	2,628
Operation, maintenance and administration	422	609	61	1,092
Depreciation and amortization	302	304	10	616
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	665	478	(8)	1,135
Financing charges				344
Income before provision for payments in lieu of corporate income taxes				791
Capital expenditures	810	628	9	1,447

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

December 31 (Canadian dollars in millions)	**2011**	**2010**
Total assets		
Transmission	10,380	9,805
Distribution	7,336	6,908
Other	652	609
	18,368	17,322

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

21. SUBSEQUENT EVENTS

On January 13, 2012, Hydro One issued $300 million in 3.20% notes under its MTN Program with a maturity date of January 13, 2022.

On February 10, 2012, Hydro One declared common dividends to its shareholder in the amount of $277 million and preferred shares of $4 million.

22. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2011 Consolidated Financial Statements.

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**	**2009**	**2008**	**2007**
Statement of operations data					
Revenues					
Transmission	1,389	1,307	1,147	1,212	1,242
Distribution	4,019	3,754	3,534	3,334	3,382
Other	63	63	63	51	31
	5,471	5,124	4,744	4,597	4,655
Costs					
Purchased power	2,628	2,474	2,326	2,181	2,240
Operation, maintenance and administration	1,092	1,078	1,057	965	995
Depreciation and amortization	616	583	537	548	521
	4,336	4,135	3,920	3,694	3,756
Income before financing charges and provision for payments in lieu of corporate income taxes	1,135	989	824	903	899
Financing charges	344	342	308	292	295
Income before provision for payments in lieu of corporate income taxes	791	647	516	611	604
Provision for payments in lieu of corporate income taxes	150	56	46	113	205
Net income	641	591	470	498	399
Basic and fully diluted earnings per common share *(Canadian dollars)*	6,228	5,727	4,528	4,797	3,809

December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	10,380	9,805	8,993	7,877	7,273
Distribution	7,336	6,908	6,481	5,873	5,407
Other	652	609	161	128	106
Total assets	18,368	17,322	15,635	13,878	12,786
Liabilities					
Current liabilities (including current portion of long-term debt)	1,820	1,540	1,655	1,300	1,452
Long-term debt	7,399	7,278	6,281	5,733	5,063
Other long-term liabilities	2,695	2,523	2,281	1,721	1,385
Shareholder's equity					
Share capital	3,637	3,637	3,637	3,637	3,637
Retained earnings	2,827	2,354	1,791	1,497	1,258
Accumulated other comprehensive income	(10)	(10)	(10)	(10)	(9)
Total liabilities and shareholder's equity	18,368	17,322	15,635	13,878	12,786

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS (continued)

Year ended December 31 (Canadian dollars in millions)	**2011**	**2010**	**2009**	**2008**	**2007**
Other financial data					
Capital expenditures					
Transmission	810	936	918	704	560
Distribution	628	629	643	570	511
Other	9	5	5	10	20
Total capital expenditures	1,447	1,570	1,566	1,284	1,091
Ratios					
Net asset coverage on long-term debt[1]	1.81	1.77	1.79	1.84	1.87
Earnings coverage ratio[2]	2.71	2.39	2.15	2.63	2.67
Operating statistics					
Transmission					
Units transmitted *(TWh)*[3]	141.5	142.2	139.2	148.7	152.2
Ontario 20-minute system peak demand *(MW)*[3]	25,505	25,145	24,477	24,231	25,809
Ontario 60-minute system peak demand *(MW)*[3]	25,450	25,075	24,380	24,195	25,737
Total transmission lines *(circuit-kilometres)*	28,942	28,951	28,924	29,039	28,915
Distribution					
Units distributed to Hydro One customers *(TWh)*[3]	29.2	29.1	28.9	29.9	30.2
Units distributed through Hydro One lines *(TWh)*[3,4]	42.5	42.5	43.5	44.7	45.7
Total distribution lines *(circuit-kilometres)*	120,514	123,552	123,528	123,260	122,933
Customers	1,365,379	1,345,177	1,333,920	1,325,745	1,311,714
Total regular employees	5,781	5,717	5,427	5,032	4,602

[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.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2012

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying financial statements of the Distribution Business (a business of Hydro One Networks Inc.), which comprise the balance sheets as at December 31, 2012, and December 31, 2011, the statements of operations and comprehensive income, and cash flows for the year ended December 31, 2012, and December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information. The financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to these financial statements.

Management's Responsibility for the Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these financial statements in accordance with the basis of accounting in Note 2 to these financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these financial statements in the circumstances, 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 audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on 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 consolidated financial statements present fairly, in all material respects, the financial position of the Distribution Business (a business of Hydro One Networks Inc.) as at December 31, 2012, and December 31, 2011, and its statements of operations and comprehensive income, and cash flows for the year ended December 31, 2012, and December 31, 2011, in accordance with basis of accounting as set out in note 2 to these financial statements.

Basis of Accounting and Restriction of Use

Without modifying our opinion, we draw attention to Note 2 to these financial statements, which describes the basis of accounting and composition of Hydro One Networks Inc.'s Distribution Business. In particular, in preparing these financial statements, long-term debt, shared functions and services costs, and payments in lieu of corporate income taxes have been allocated to the Distribution Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to these financial statements. As a result of this basis of accounting, these financial statements may not necessarily be identical to the financial position, results of operations and cash flows that would have resulted had the Distribution Business (a business of Hydro One Networks Inc.) historically operated as a stand-alone basis. These financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, these financial statements may not be suitable for another purpose. Our report is intended solely for Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Accountants, Licensed Public Accountants
Toronto, Canada
April 18, 2013

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	**2012**	**2011**
Revenues		*(Note 22)*
Energy sales	3,536	3,398
Rural rate protection *(Note 18)*	125	125
Other	53	46
	3,714	3,569
Costs		
Purchased power *(Note 18)*	2,413	2,285
Operation, maintenance and administration *(Note 18)*	553	555
Depreciation and amortization *(Note 4)*	308	287
	3,274	3,127
Income before financing charges and provision for payments in lieu of corporate income taxes	440	442
Financing charges *(Notes 5, 18)*	138	140
Income before provision for payments in lieu of corporate income taxes	302	302
Provision for payments in lieu of corporate income taxes *(Notes 6, 18)*	44	66
Net income	258	236
Other comprehensive income	-	-
Comprehensive income	258	236

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS

December 31 (millions of dollars)	**2012**	**2011**
Assets		*(Note 22)*
Current assets:		
Inter-company demand facility *(Notes 12, 13, 18)*	5	141
Accounts receivable (net of allowance for doubtful accounts - $20; 2011 - $15) *(Notes 7,18)*	778	744
Regulatory assets *(Note 10)*	14	9
Materials and supplies	7	4
Deferred income tax assets *(Note 6)*	7	8
Other	12	7
	823	913
Property, plant and equipment *(Note 8)*:		
Property, plant and equipment in service	8,363	7,863
Less: accumulated depreciation	3,078	2,870
	5,285	4,993
Construction in progress	314	293
Future use land, components and spares	45	39
	5,644	5,325
Other long-term assets:		
Regulatory assets *(Note 10)*	612	431
Intangible assets (net of accumulated amortization - $178; 2011 - $154) *(Note 9)*	159	108
Goodwill	73	73
Deferred debt costs	12	11
Derivative instruments *(Note 12)*	5	9
	861	632
Total assets	7,328	6,870

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS (continued)

December 31 (millions of dollars)	**2012**	**2011**
Liabilities		*(Note 22)*
Current liabilities:		
Accounts payable	58	49
Accrued liabilities *(Notes 6, 14, 15, 18)*	592	643
Accrued interest *(Note 18)*	35	31
Regulatory liabilities *(Note 10)*	38	16
Long-term debt payable within one year *(Notes 11, 12, 13, 18)*	230	324
	953	1,063
Long-term debt *(Notes 11, 12, 13, 18)*	2,785	2,565
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 14)*	785	646
Deferred income tax liabilities *(Note 6)*	230	171
Environmental liabilities *(Note 15)*	132	134
Regulatory liabilities *(Note 10)*	96	105
Net unamortized debt premiums	12	11
Asset retirement obligations *(Note 16)*	3	3
Long-term accounts payable and other liabilities	13	4
	1,271	1,074
Total liabilities	5,009	4,702
Contingencies and commitments (Notes 20, 21)		
Excess of assets over liabilities *(Notes 13, 17)*	2,319	2,168
Total liabilities and excess of assets over liabilities	7,328	6,870

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Carmine Marcello
Chair

Sandy Struthers
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2012**	**2011**
Operating activities		*(Note 22)*
Net income	258	236
Environmental expenditures	(9)	(8)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	262	242
Regulatory assets and liabilities	(5)	40
Deferred income taxes	2	(9)
Other	1	1
Changes in non-cash balances related to operations *(Note 19)*	(44)	128
Net cash from operating activities	465	630
Financing activities		
Long-term debt issued	454	225
Long-term debt retired	(324)	(176)
Payments to Hydro One Inc. to finance dividends	(107)	(45)
Other	-	(1)
Net cash from financing activities	23	3
Investing activities		
Capital expenditures		
Property, plant and equipment	(562)	(539)
Intangible assets	(74)	(57)
Other	12	18
Net cash used in investing activities	(624)	(578)
Net change in inter-company demand facility	(136)	55
Inter-company demand facility, beginning of year	141	86
Inter-company demand facility, end of year	5	141

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP). These Financial Statements are to be read in conjunction with Note 22 - Transition to US GAAP, which discloses information on the Canadian GAAP, per Part V of the Canadian Institute of Chartered Accountants Handbook (Canadian GAAP), to US GAAP transition and related reconciliations from Canadian GAAP to US GAAP. The results of operations for the year ended December 31, 2011, and the Balance Sheets as at December 31, 2011 have been restated under US GAAP for comparative purposes.

These Financial Statements have been prepared for the specific use of the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2012 have been prepared and are publicly available.

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Distribution Business on a basis approved by the OEB. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company's Distribution Business. As a result of this basis of accounting, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Distribution Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Payments in lieu of corporate income taxes (PILs) have been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Distribution Business was a separate taxpaying entity. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events for the accompanying Financial Statements and notes included through to April 18, 2013, the date these Financial Statements were available to be issued, to determine whether the circumstances warranted recognition and disclosure of any events or transactions. No such events or transactions were identified.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an on going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumptions are made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill, asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB or the Province.

Rate Setting

The OEB has approved the Company's request to use US GAAP as the basis for rate setting and regulatory accounting and reporting for its Distribution Business, effective January 1, 2012.

In 2009, Hydro One Networks filed a cost-of-service application with the OEB for 2011 distribution rates, seeking approval for a revenue requirement of approximately $1,264 million. The application reflected 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 to make investments required by the Green Energy Act. In April 2010, the OEB approved a revenue requirement of $1,236 million for 2011. The OEB also approved certain distribution regulatory account balances sought by Hydro One Networks in its application, including retail settlement variance accounts, retail cost variance accounts and smart meters. In November 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. A lowering of the return on equity produced a revised revenue requirement of $1,218 million. Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for the 2011 rate year.

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 Distribution Business' 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 Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to electricity customers. The Distribution Business 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 Distribution Business judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition

Distribution revenues are recognized on an accrual basis and include billed and unbilled revenues. 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 monthly revenue for a period based on wholesale electricity purchases because customer meters are not generally read at the end of each month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes. 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. Current legislation provides rate protection for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount or net realizable value, if unbilled. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Distribution Business' best estimate of losses on accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Distribution Business estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the amount billed is not received within 120 days of the invoiced date. Accounts receivable are written off against the allowance when they are deemed uncollectible. The existing allowance for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One Networks is required to remit 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) as modified by the *Electricity Act, 1998* and related regulations.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

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.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred 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 at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the deferred income tax asset to report the net asset balance at the amount expected to be realized. Previously unrecognized deferred 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 the tax benefit will be realized.

The Distribution Business has recognized regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Distribution Business uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only the ITCs are recognized as a reduction to income tax expense.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions received in aid of construction and any accumulated impairment losses. The cost of additions, including betterments and replacements of asset components, is included on the Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overhead includes a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Distribution

Distribution assets include 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, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include amounts incurred to acquire land rights and other access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Distribution Business' intangible assets primarily represent major administrative computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs directly attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Distribution Businesss' weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

Hydro One periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2007.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate (%)	
	Service Life	Range	Average
Distribution	42 years	1% - 5%	2%
Communication	11 years	1% - 13%	5%
Administration and service	17 years	1% - 15%	8%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software assets range from 9% to 11%.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation and amortization, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment assets where no ARO has been recorded.

Goodwill

Goodwill represents the cost of acquired local distribution companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate-base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Per Accounting Standards Update (ASU) 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment, issued by the Financial Accounting Standards Board (FASB) in September 2011, the Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

For the year ended December 31, 2012, based on the qualitative assessment performed, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 2012.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of the Distribution Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2012, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the Balance Sheets. Deferred debt costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges, and the change in fair value on the Company's proportionate share of existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its share of unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the allocated hedged debt. OCI and net income are presented in a single continuous Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities 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. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. Hydro One Networks determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with its risk management policy disclosed in Note 12 – Fair Value of Financial Instruments and Risk Management.

All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various derivative instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedge relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are then allocated between the Company's transmission and distribution businesses.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value in the Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized in its Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Statement of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Statements of Operations and Comprehensive Income. Additionally, Hydro One enters into derivative agreements that are economic hedges that either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and carried at fair value on the Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2012.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where Hydro One has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment funds are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The net asset for an overfunded plan is classified as a long-term asset in the Consolidated Balance Sheets. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets. For the year ended December 31, 2012, the measurement date for the Plans was December 31.

Pension benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the pension plan 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.

A detailed description of Hydro One pension benefits is provided in Note 14 - Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2012.

Post-retirement and post-employment benefits

The Company records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded on transition to US GAAP and at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits, are recorded and included in rates 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 are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in Note 14 - Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2012.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Distribution Business' Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Distribution Business records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Distribution Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. The Distribution Business records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The present value is determined with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As it is anticipated that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. The estimates of future environmental expenditures are reviewed annually or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

AROs are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional AROs are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an ARO, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in-service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

Some distribution assets, particularly those located on unowned easements and rights-of-way, may have AROs, 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 Distribution Business expects to use the majority of its facilities in perpetuity, no ARO currently exists for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable ARO exists. In such a case, an ARO would be recorded at that time.

The Distribution Business' AROs recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In September 2011, the FASB issued ASU 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment. This ASU is intended to reduce the cost and complexity of the annual goodwill impairment test by providing entities an option to perform a qualitative assessment to determine whether further impairment testing is necessary. An entity has the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step test. If an entity believes, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount, the quantitative impairment test is required. Otherwise, no further testing is required. An entity can choose to perform the qualitative assessment on none, some or all of its reporting units. Moreover, an entity can bypass the qualitative assessment for any reporting unit in any period and proceed directly to step one of the impairment test, and then resume performing the qualitative assessment in any subsequent period. The adoption of this ASU did not have a significant impact on the Distribution Business' Financial Statements.

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income, to clarify that an entity has the option to present the total of comprehensive income, the components of net income, and the components of OCI either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of OCI along with a total for OCI, and a total amount for comprehensive income. This update eliminates the option to present the components of OCI as part of the statement of changes in shareholders' equity. The amendments in this ASU do not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. The Distribution Business has elected to present OCI and net income in a single continuous Statement of Operations and Comprehensive Income.

In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in US GAAP and IFRSs. This ASU is the result of joint efforts by the FASB and the International Accounting Standards Board to develop common, converged fair value guidance on how to measure fair value and on what disclosures to provide about fair value measurements. This ASU is largely consistent with existing US GAAP fair value measurement principles under Accounting Standards Codification 820. However, this ASU expands the existing disclosure requirements for fair value measurements, particularly of Level 3 inputs, and requires categorization by level of the fair value hierarchy for items that are not measured at fair value on the Balance Sheets but for which the fair value is required to be disclosed. Required disclosures have been included in Note 12 – Fair Value of Financial Instruments and Risk Management. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Distribution Business' Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the Balance Sheets as well as financial instruments and transactions executed under a master netting or similar arrangement and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on its financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this ASU only requires enhanced disclosures, the adoption of this ASU is not anticipated to have a significant impact on the Distribution Business' Financial Statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of dollars)	**2012**	**2011**
Depreciation of property, plant and equipment	229	212
Amortization of intangible assets	24	22
Asset removal costs	46	45
Amortization of regulatory assets	9	8
	308	287

5. FINANCING CHARGES

Year ended December 31 (millions of dollars)	**2012**	**2011**
Interest on long-term debt	154	152
Other	8	4
Less: Interest capitalized on construction and development in progress	(18)	(11)
Gain on interest-rate swap agreements	(4)	(3)
Interest earned on inter-company demand facility	(2)	(2)
	138	140

6. 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 the effective tax rates is provided as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Income before provision for PILs	302	302
Canadian Federal and Ontario statutory income tax rate	26.50%	28.25%
Provision for PILs at statutory rate	80	85
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(8)	(4)
Interest capitalized for accounting but deducted for tax purposes	(4)	(3)
Pension contributions in excess of pension expense	(12)	(10)
Overheads capitalized for accounting but deducted for tax purposes	(6)	(5)
Environmental expenditures	(2)	(2)
Non-refundable ITCs	(6)	-
Post-retirement and post-employment benefit expense in excess of cash payments	-	3
Other	1	1
Net temporary differences	(37)	(20)
Net permanent differences	1	1
Total provision for PILs	44	66
Current provision for PILs	42	75
Deferred provision for PILs	2	(9)
Total provision for PILs	44	66
Effective income tax rate	14.57%	21.85%

The current provision for PILs of $42 million (2011 - $75 million) represents the amount paid or payable to the OEFC with respect to current year income. The outstanding balance due to the OEFC at December 31, 2012 was $7 million (2011 - $30 million).

The total provision for PILs includes deferred provision for PILs of $2 million (2011 - recovery of $9 million) that is not included in the rate-setting process, using the balance sheet liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. At December 31, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of dollars)	**2012**	**2011**
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	290	200
Environmental expenses	36	36
Other	1	1
Total deferred income tax assets	327	237
Less: current portion	10	10
	317	227

December 31 (millions of dollars)	**2012**	**2011**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	458	374
Distribution amounts received but not recognized for accounting purposes	84	19
Goodwill	8	7
Total deferred income tax liabilities	550	400
Less: current portion	3	2
	547	398

The deferred income tax assets and liabilities are presented on the Balance Sheets as follows:

December 31 (millions of dollars)	**2012**	**2011**
Current deferred income tax assets	10	10
Current deferred income tax liabilties	(3)	(2)
Net current deferred income tax assets	7	8
Long-term deferred income tax assets	317	227
Long-term deferred income tax liabilities	(547)	(398)
Net long-term deferred income tax liabilities	(230)	(171)

During 2012, the deferred tax liability increased by $14 million as a result of the change in the rate applicable to future taxes.

7. ACCOUNTS RECEIVABLE

December 31 (millions of dollars)	**2012**	**2011**
Accounts receivable – billed	200	214
Accounts receivable – unbilled	598	545
Accounts receivable, gross	798	759
Allowance for doubtful accounts	(20)	(15)
Accounts receivable, net	778	744

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2012 and 2011.

Year ended December 31 (millions of dollars)	**2012**	**2011**
Allowance for doubtful accounts – January 1	(15)	(22)
Write-offs	16	29
Additions to allowance for doubtful accounts	(21)	(22)
Allowance for doubtful accounts – December 31	(20)	(15)

8. PROPERTY, PLANT AND EQUIPMENT

December 31 (millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
2012				
Distribution	7,476	2,602	220	5,094
Communication	100	21	-	79
Administration and Service	824	451	94	467
Easements	8	4	-	4
	8,408	3,078	314	5,644
2011				
Distribution	7,090	2,440	243	4,893
Communication	30	16	-	14
Administration and Service	774	410	50	414
Easements	8	4	-	4
	7,902	2,870	293	5,325

Financing charges capitalized on property, plant and equipment under construction were $15 million (2011 - $10 million).

9. INTANGIBLE ASSETS

December 31 (millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2012				
Computer applications software	228	176	107	159
Other assets	2	2	-	-
	230	178	107	159
2011				
Computer applications software	217	153	44	108
Other assets	1	1	-	-
	218	154	44	108

Financing charges capitalized on intangible assets under development were $3 million (2011 - $1 million). The estimated annual amortization expense for intangible assets for each of the next five years is $21 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 (millions of dollars)	**2012**	**2011**
Regulatory assets:		
Deferred income tax	239	181
Post-retirement and post-employment benefits	180	70
Environmental	140	142
Pension cost variance	46	29
Rider 2	10	11
Other	11	7
Total regulatory assets	626	440
Less: current portion	14	9
	612	431
Regulatory liabilities:		
Retail settlement variance accounts	46	40
Rider 8	45	42
PST savings deferral	10	6
Rider 3	9	9
Deferred income tax	7	7
Rural and remote rate protection variance	6	8
Other	11	9
Total regulatory liabilities	134	121
Less: current portion	38	16
	96	105

Deferred Income Tax

Deferred 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 Distribution Business has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-making process. In the absence of rate-regulated accounting, the Distribution Business' provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be reflected in future rates. As a result, the 2012 provision for PILs would have been higher by approximately $41 million (2011 - $22 million), including the impact of a change in enacted tax rates.

Post-Retirement and Post-Employment Benefits

The Distribution Business recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $110 million (2011 – higher by $16 million).

Environmental

The Distribution Business records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 15 – Environmental Liabilities). Because such expenditures are expected to be recoverable in future rates, the Distribution Business has recorded an equivalent amount as a regulatory asset. In 2012, the Company's PCB liability decreased by $2 million (2011 - $23 million) to reflect a revaluation adjustment in the Company's PCB liability and increased by $2 (2011 – no change) for a revision to the Company's LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, there would have been no change in 2012 operation, maintenance and administration expenses (2011 – lower by $23 million). In addition, 2012 amortization expense would have been lower by $9 million (2011 – $8 million), and 2012 financing charges would have been higher by $6 million (2011 – $8 million).

Pension Cost Variance

A pension cost variance account was established for the Distribution Business to track the difference between the actual pension expense incurred and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension contributions as compared to OEB-approved amounts. In December 2010, 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, 2012 revenue would have been lower by $17 million (2011 - $13 million).

Rider 2

In April 2006, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by the Company. The Rider 2 regulatory asset includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

Retail Settlement Variance Accounts (RSVA)

The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In April 2010, the OEB approved the disposition of the total RSVA balance accumulated from May 2008 to December 2009, including accrued interest, to be disposed over a 20-month period from May 1, 2010 to December 31, 2011. The Company has continued to accumulate a net liability in its RSVA accounts since December 31, 2009.

Rider 8

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administrative expenses or capital expenditures for past revenue requirements approved during a full cost of service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administrative expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable and calculations for tracking and refund were requested by the OEB. For the Distribution Business, PST was included in rates between July 1, 2010 and December 31, 2012 and this amount has been recorded in a deferral account per direction from the OEB.

Rider 3

In December 2008, the OEB approved certain distribution-related deferral account balances sought by the Company, including RSVA amounts, deferred tax changes, OEB costs and smart meters. The OEB approved the disposition of the Rider 3 balance accumulated up to April 2008, including accrued interest, to be disposed over a 27-month period from February 1, 2009 to April 30, 2011.

Rural and Remote Rate Protection Variance (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. The OEB has 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 in the RRRP variance account.

11. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, which is then allocated between the Company's transmission and distribution businesses.

The following table presents the outstanding long-term debt of the Distribution Business as at December 31, 2012 and 2011:

December 31 (millions of dollars)	**2012**	**2011**
Long-term debt	3,010	2,880
Add: Unrealized marked-to-market loss[1]	5	9
Less: Long-term debt payable within one year	(230)	(324)
Long-term debt	2,785	2,565

[1] The unrealized marked-to-market loss relates to $100 million of Distribution Business' $175 million note due 2014, and $100 million of Distribution Business' $200 million note due 2015. The unrealized marked-to-market loss is offset by a $5 million (2011 - $9 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 12 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 12 – Fair Value of Financial Instruments and Risk Management.

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Company classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occurs with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non−Derivative Financial Assets and Liabilities

At December 31, 2012 and 2011, the carrying amounts of accounts receivable, inter-company demand facility, accounts payable and accrued liabilities are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Distribution Business' long-term debt at December 31, 2012 and 2011 are as follows:

December 31 (millions of dollars)	2012 Carrying Value	2012 Fair Value	2011 Carrying Value	2011 Fair Value
Long-term debt				
$100 million of $175 million notes due 2014[1]	102	102	104	104
$100 million of $200 million notes due 2015[2]	103	103	105	105
Other notes and debentures[3]	2,810	3,338	2,680	3,180
	3,015	3,543	2,889	3,389

[1] The fair value of $100 million of Distribution Business' $175 million notes due 2014, subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of $100 million of Distribution Business' $200 million notes due 2015, subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[3] The fair value of other notes and debentures, and the portions of Distribution Business' $175 million and $200 million notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are then allocated between the Company's transmission and distribution businesses.

At December 31, 2012, the Distribution Business' share of the Company's derivative instruments include $200 million of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt (2011 - $200 million). These interest-rate swaps are classified as fair value hedges. The Distribution Business' fair value hedge exposure was equal to about 7% (2011 – 7%) of its long-term debt. At December 31, 2012, the Distribution Business' interest-rate swaps designated as fair value hedges were as follows:

(a) a $100 million fixed-to-floating interest-rate swap agreement to convert $100 million of the $175 million notes maturing November 19, 2014 into three-month variable rate debt; and

(b) two $50 million fixed-to-floating interest-rate swap agreements to convert $100 million of the $200 million notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2012, the Distribution Business' share of interest-rate swaps classified as undesignated contracts consisted of the following:

(c) three $100 million floating-to-fixed interest-rate swap agreements that lock in the floating-rate on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2012 to December 11, 2013, from February 21, 2012 to February 19, 2013, and from February 19, 2013 to February 19, 2014, respectively;

(d) two $20 million floating-to-fixed interest-rate swap agreements that lock in the floating-rate on the $20 million floating-rate notes maturing July 24, 2015, from January 24, 2012 to January 24, 2013, and from January 24, 2013 to January 24, 2014, respectively, and;

(e) a $20 million floating-to-fixed interest-rate swap agreement that locks in the floating-rate on the $20 million floating-rate notes maturing December 3, 2016, from March 4, 2013 to December 3, 2013.

At December 31, 2012 and 2011, the carrying amounts of derivative instruments were representative of fair value.

Fair Value Hierarchy

Fair value hierarchy information for financial assets and liabilities at December 31, 2012 and 2011 was as follows:

December 31, 2012 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	5	5	5	-	-
Derivative instruments					
Fair value hedges – interest-rate swaps	5	5	-	5	-
	10	10	-	10	-
Liabilities:					
Long-term debt	3,015	3,543	-	3,543	-
	3,015	3,543	-	3,543	-

December 31, 2011 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	141	141	141	-	-
Derivative instruments					
Fair value hedges – interest-rate swaps	9	9	-	9	-
	150	150	141	9	-
Liabilities:					
Long-term debt	2,889	3,389	-	3,389	-
	2,889	3,389	-	3,389	-

The fair value of the derivative instruments is determined using other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the un-hedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2012 and 2011.

Risk Management

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 capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although Hydro One could in the future decide to issue foreign currency-denominated debt which would be hedged back to Canadian dollars consistent with its risk management policy. This could be mirrored in the Company. The Company is exposed to fluctuations in interest rates as the regulated rate of return for its Distribution Business is derived using a formulaic approach that 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 Distribution Business' rate of return would reduce the Distribution Business' results of operations by approximately \$10 million (2011 - \$10 million).

Hydro One uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One also uses derivative financial instruments to manage interest-rate risk. Hydro One utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, Hydro One may utilize interest-rate derivative instruments to lock in interest rate levels in anticipation of future financing. Hydro One may also 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. Such arrangements are typically designated as cash flow hedges. The Company's derivative instrument policy is consistent with Hydro One. No cash flow hedge agreements outstanding as at December 31, 2012 or 2011.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in the Distribution Business' results of operations for the years ended December 31, 2012 or 2011.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instruments as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The Distribution Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2012 and 2011 are included in financing charges as follows:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Unrealized (gain) loss on hedged debt	(4)	7
Unrealized loss (gain) on fair value interest-rate swaps	4	(7)
Net unrealized loss (gain)	-	-

At December 31, 2012, the notional amount of the Distribution Business' fair value hedges outstanding related to interest-rate swaps was \$200 million (2011 - \$200 million), with assets at fair value of \$5 million (2011 - \$9 million). During the years ended December 31, 2012 and 2011, there was no significant impact on the Distribution Business' results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2012 and 2011, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business did not earn a significant amount of revenue from any individual customer. At December 31, 2012 and 2011, there was no significant accounts receivable balance due from any single customer.

At December 31, 2012, the Distribution Business' allowance for doubtful accounts was \$20 million (2011 - \$15 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2012, approximately 2% of the Distribution Business' accounts receivable were aged more than 60 days (2011 - 1%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Hydro One'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 counterparties. In addition to payment netting language in master agreements, Hydro One establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. Hydro One would only offset the positive market values against negative values with the same counterparty where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Hydro One as specified in each agreement. Hydro One monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk policy is consistent with Hydro One. The Distribution Business' credit risk for accounts receivable is limited to the carrying amounts on its Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2012, the counterparty credit risk exposure on the fair value of the Distribution Business' share of these interest-rate swap contracts was $6 million (2011 - $10 million). At December 31, 2012, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties. The credit exposure of each of the four counterparties accounted for more than 10% of the total credit exposure.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. The Company meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

At December 31, 2012, accounts payable and accrued liabilities in the amount of $650 million (2011 - $692 million) were expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2012, the notional amount of the Distribution Business' long-term debt was $3,010 million (2011 – $2,880 million). Long-term debt maturing over the next twelve months was $230 million (2011 - $324 million). Interest payments for the next 12 months on the outstanding long-term debt were $146 million (2011 – $150 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 Long-term Debt	Interest Payments[1]	Weighted Average Interest Rate[1]
	(millions of dollars)	*(millions of dollars)*	*(%)*
1 year	230	146	5.0
2 years	175	135	3.2
3 years	220	129	2.9
4 years	200	119	4.4
5 years	195	115	5.2
	1,020	644	4.1
6 - 10 years	381	506	3.6
Over 10 years	1,609	1,498	5.7
	3,010	2,648	4.9

[1] Interest payments and weighted average interest rates beyond one year exclude the impact of Distribution Business' $20 million floating-rate notes due 2015 and Distribution Business' $20 million floating-rate notes due 2016.

13. CAPITAL MANAGEMENT

The Distribution Business' objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB.

The Distribution Business considers its capital structure to consist of excess of assets over liabilities, long-term debt, and the inter-company demand facility. The following table summarizes this capital structure:

December 31 (millions of dollars)	**2012**	**2011**
Long-term debt payable within one year	230	324
Inter-company demand facility	(5)	(141)
	225	183
Long-term debt	2,785	2,565
Excess of assets over liabilities	2,319	2,168
Total capital	5,329	4,916

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2012 and 2011:

December 31 (millions of dollars)	**2012**	**2011**
Excess of assets over liabilities, January 1	2,168	1,976
Net income	258	236
OCI	-	-
Payments to Hydro One to finance dividends	(107)	(45)
Excess of assets over liabilities, December 31	2,319	2,168

14. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks Inc. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included in post-retirement and post-employment benefit liability on the Balance Sheets.

Pension Benefits

The 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 represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Hydro One's annual Pension Plan contributions for 2012 of $163 million (2011 – $152 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2012 pensionable earnings. Hydro One's estimated annual Pension Plan contributions for 2013 are approximately $160 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

At December 31, 2012, based on the December 31, 2011 actuarial valuation, the present value of Hydro One's projected pension benefit obligation was estimated to be $6,507 million (2011 - $5,461 million). The fair value of Pension Plan assets available for these benefits was $4,992 million (2011 - $4,682 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2012, the Distribution Business charged $26 million (2011 – $33 million) of post-retirement and post-employment benefit costs to operations, and capitalized $28 million (2011 - $23 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2012 were $25 million (2011 - $23 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was increased by $110 million (2011 – decreased by $15 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets within the following line items:

December 31 (millions of dollars)	**2012**	**2011**
Accrued liabilities	22	22
Post-retirement and post-employment benefit liability	785	646
	807	668

15. ENVIRONMENTAL LIABILITIES

The following discounted amounts for environmental liabilities were recorded on the Balance Sheets at December 31, 2012 and 2011:

December 31 (millions of dollars)	PCB	LAR	Total
2012			
Environmental liabilities, January 1	116	27	143
Interest accretion	6	-	6
Expenditures	(4)	(5)	(9)
Revaluation adjustment	(2)	2	-
Environmental liabilities, December 31	116	24	140
Less: current portion	3	5	8
	113	19	132

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Environmental liabilities, January 1	135	31	166
Interest accretion	7	1	8
Expenditures	(3)	(5)	(8)
Revaluation adjustment	(23)	-	(23)
Environmental liabilities, December 31	116	27	143
Less: current portion	5	4	9
	111	23	134

The following table illustrates the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized in the Balance Sheets after factoring in the discount rate:

December 31 (millions of dollars)	PCB	LAR	Total
2012			
Undiscounted environmental liabilities, December 31	135	25	160
Less: discounting accumulated liabilities to present value	(19)	(1)	(20)
Discounted environmental liabilities, December 31	116	24	140

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Undiscounted environmental liabilities, December 31	138	28	166
Less: discounting accumulated liabilities to present value	(22)	(1)	(23)
Discounted environmental liabilities, December 31	116	27	143

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2012 and in total thereafter are as follows: 2013 - $9 million; 2014 - $22 million; 2015 - $22 million; 2016 - $19 million; 2017 - $15 million; and thereafter - $73 million. At December 31, 2012, of the total estimated future environmental expenditures, $135 million related to PCB (2011 - $138 million) and $25 million related to LAR (2011 - $28 million).

Consistent with the Company's accounting policy for environmental costs, the Distribution Business records a liability for the estimated mandatory 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.

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 Distribution Business' environmental liabilities represent management's best estimates of the present value of the 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 current assumptions. In addition, with respect to the PCB environmental liability, 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. The Distribution Business records a regulatory asset reflecting its expectation that future environmental costs will be recoverable in rates.

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. The Distribution Business' 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

In September 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*. These regulations impose timelines for disposal of PCBs based on certain 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, with the exception of specifically exempted equipment. 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 Distribution Business currently has very few PCB-contaminated assets in excess of 500 ppm. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains a PCB concentration of less than 2 ppm.

The Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is approximately $135 million. These expenditures are expected to be incurred over the period from 2013 to 2025. As a result of the Company's most recent cost estimate to comply with current PCB regulations, the Distribution Business recorded a revaluation adjustment to reduce the PCB environmental liability by approximately $2 million (2011 – $23 million).

LAR

The Distribution Business' best estimate of the total estimated future expenditures to complete its LAR Program is approximately $25 million. These expenditures are expected to be incurred over the period from 2013 to 2020. As part of its annual review of environmental liabilities, the Company also reviewed its liability for LAR. As a result of this review, the Distribution Business recorded a revaluation adjustment to increase the LAR environmental liability by approximately $2 million (2011 - $nil).

16. ASSET RETIREMENT OBLIGATIONS

AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO (with corresponding adjustments to property, plant, and equipment), which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired and changes in federal, state or local regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

All factors used in estimating the Distribution Business' AROs 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 current assumptions. AROs 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 AROs, 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.

At December 31, 2012, the Company had recorded AROs of $3 million (2011 – $3 million) related to its Distribution Business, consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal and there have been no expenditures associated with these obligations to date.

The Company's liability for the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities is based on management's best estimate of the present value of the estimated future expenditures to comply with current regulations. In 2010, the Company completed a study with the aid of an external expert to estimate the future expenditures required to remove asbestos prior to facility demolition.

17. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks has 14,875,720 issued and outstanding cumulative preferred shares and 148,821,741 issued and outstanding common shares. The Company is authorized to issue an unlimited number of preferred shares and common shares.

Hydro One Networks makes common share and preferred share dividend payments to Hydro One. The Distribution Business makes payments to finance its share of the Company's common share and preferred share dividends. During 2012, the Distribution Business' payments to finance these dividends totaled $107 million (2011 - $45 million).

18. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of a subsidiary of Hydro One, and Hydro One is owned by the Province. The OEFC, IESO, Ontario Power Authority (OPA), Ontario Power Generation Inc. (OPG) and the OEB are related parties to the Distribution Business because they are controlled or significantly influenced by the Province. Transactions between these parties and the Distribution Business are described below.

The Distribution Business receives amounts for rural rate protection from the IESO. 2012 revenues include $125 million (2011 – $125 million) related to this program.

In 2012, the Distribution Business purchased power in the amount of $2,031 million (2011 - $2,057 million) from the IESO-administered electricity market, $10 million (2011 - $16 million) from OPG, and $7 million (2011 - $10 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 2012, the Distribution Business incurred $6 million (2011 - $7 million) in OEB fees.

The Company has service level agreements with OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Operation, maintenance and administration costs of the Distribution Business related to the purchase of services with respect to these service level agreements were less than $1 million in both 2012 and 2011.

The OPA funds substantially all of the Company's Conservation and Demand Management (CDM) programs. The funding includes program costs, incentives, and management fees. In 2012, the Distribution Business received $32 million (2011 - $38 million) from the OPA related to these CDM programs.

PILs were paid or payable to the OEFC.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (millions of dollars)	2012	2011
Accounts receivable	32	36
Accrued liabilities[1]	(184)	(237)

[1] Included in accrued liabilities at December 31, 2012 are amounts owing to the IESO in respect of power purchases of $172 million (2011 – $182 million).

Hydro One and Subsidiaries

The Distribution Business 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.

The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of shared corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2012 revenues of the Distribution Business include $2 million (2011 - $2 million) related to the provision of services to Hydro One and its subsidiaries. Operation, maintenance and administration costs of the Distribution Business include $11 million (2011 - $10 million) related to the services received from Hydro One and its subsidiaries.

The Distribution Business' long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or due from Hydro One. Financing charges include interest expense on the long-term debt in the amount of $154 million (2011 - $152 million), and interest income on the inter-company demand facility in the amount of $2 million (2011 - $2 million). At December 31, 2012, the Distribution Business had accrued interest payable to Hydro One totaling $35 million (2011 - $31 million).

19. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of dollars)	**2012**	**2011**
Accounts receivable	(34)	(34)
Materials and supplies	(3)	1
Other assets	(5)	(4)
Accounts payable	9	6
Accrued liabilities	(53)	123
Accrued interest	4	-
Long-term accounts payable and other liabilities	9	-
Post-retirement and post-employment benefit liability	29	33
	(44)	125

Supplementary information:		
Net interest paid	150	152
PILs	81	31

20. CONTINGENCIES

The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available for the satisfaction of the debts, contingent liabilities and commitments of both the Company and Hydro One.

21. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the net assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

22. TRANSITION TO US GAAP

The adoption of US GAAP has been made on a retrospective basis with restatement of comparative information to reflect US GAAP requirements in effect at that time. The Distribution Business' transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to its 2012 Financial Statements.

Measurement and classification differences resulting from the Distribution Business' adoption of US GAAP are presented below. With respect to measurement and classification differences, the tables under the heading US GAAP Differences, represent quantitative reconciliations of the Balance Sheets previously presented in accordance with Canadian GAAP, to the respective amounts and classifications under US GAAP, together with descriptions of the various significant measurement and classification differences arising from the adoption of US GAAP. Balance Sheets reconciliations are presented as at January 1, 2011 and December 31, 2011, representing the commencement and ending dates of the comparative financial year to 2012. There were no measurement or classification differences resulting from the Distribution Business' adoption of US GAAP on the Statements of Operations and Comprehensive Income.

Except as otherwise disclosed in this note, the change in basis of accounting from Canadian GAAP to US GAAP did not materially impact accounting policies or disclosures. Reference should be made to the Canadian GAAP Financial Statements as at and for the year ended December 31, 2011 for additional information on Canadian GAAP accounting policies and practices.

The following table summarizes the increases to total assets:

(millions of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total assets – Canadian GAAP		6,344	6,789
Deferred debt costs	A	11	11
Regulatory assets	B	86	70
Total assets – US GAAP		6,441	6,870

The following table summarizes the increases (decreases) to total liabilities:

(millions of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total liabilities – Canadian GAAP		4,368	4,621
Long-term debt	A	(2)	-
Net unamortized debt premiums	A	13	11
Post-retirement and post-employment benefit liability	B	86	70
Total liabilities – US GAAP		4,465	4,702

US GAAP Differences

The reconciliations of the January 1, 2011 and December 31, 2011 Balance Sheets from Canadian GAAP to US GAAP are as follows:

January 1, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Inter-company demand facility		86	-	86
Accounts receivable		710	-	710
Regulatory assets		25	-	25
Materials and supplies		5	-	5
Deferred income tax assets		12	-	12
Other		2	-	2
		840	-	840
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		4,707	-	4,707
Construction in progress		269	-	269
Future use land, components and spares		39	-	39
		5,015	-	5,015
Other long-term assets:				
Regulatory assets	B	338	86	424
Intangible assetss (net of accumulated amortization)		76	-	76
Goodwill		73	-	73
Deferred debt costs	A	-	11	11
Derivative instruments	C	-	1	1
Other	C	2	(1)	1
		489	97	586
Total assets		6,344	97	6,441
Liabilities				
Current liabilities:				
Accounts payable and accrued charges	D	561	(561)	-
Accounts payable	D	-	43	43
Accrued liabilities	D	-	518	518
Accrued interest		31	-	31
Regulatory liabilities		47	-	47
Long-term debt payable within one year		176	-	176
		815	-	815
Long-term debt	A	2,658	(2)	2,656
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	543	86	629
Deferred income tax liabilities		154	-	154
Environmental liabilities		157	-	157
Regulatory liabilities		34	-	34
Net unamortized debt premiums	A	-	13	13
Asset retirement obligations		3	-	3
Long-term accounts payable and other liabilities		4	-	4
		895	99	994
Total liabilities		4,368	97	4,465
Excess of assets over liabilities		1,976	-	1,976
Total liabilities and excess of assets over liabilities		6,344	97	6,441

December 31, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Inter-company demand facility		141	-	141
Accounts receivable		744	-	744
Regulatory assets		9	-	9
Materials and supplies		4	-	4
Deferred income tax assets		8	-	8
Other		7	-	7
		913	-	913
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		4,993	-	4,993
Construction in progress		293	-	293
Future use land, components and spares		39	-	39
		5,325	-	5,325
Other long-term assets:				
Regulatory assets	B	361	70	431
Intangible assetss (net of accumulated amortization)		108	-	108
Goodwill		73	-	73
Deferred debt costs	A	-	11	11
Derivative instruments	C	-	9	9
Other	C	9	(9)	-
		551	81	632
Total assets		6,789	81	6,870
Liabilities				
Current liabilities:				
Accounts payable and accrued charges	D	692	(692)	-
Accounts payable	D	-	49	49
Accrued liabilities	D	-	643	643
Accrued interest		31	-	31
Regulatory liabilities		16	-	16
Long-term debt payable within one year		324	-	324
		1,063	-	1,063
Long-term debt		2,565	-	2,565
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	576	70	646
Deferred income tax liabilities		171	-	171
Environmental liabilities		134	-	134
Regulatory liabilities		105	-	105
Net unamortized debt premiums	A	-	11	11
Asset retirement obligations		3	-	3
Long-term accounts payable and other liabilities		4	-	4
		993	81	1,074
Total liabilities		4,621	81	4,702
Excess of assets over liabilities		2,168	-	2,168
Total liabilities and excess of assets over liabilities		6,789	81	6,870

Notes to the Transitional Adjustments

Under US GAAP, the Distribution Business (i) measures certain assets and liabilities differently than it had under Canadian GAAP (see details on each measurement change below); and (ii) discloses certain assets, liabilities and equity on different lines in the Financial Statements than it had under Canadian GAAP (see details on each classification change below).

A. Debt Issuance Costs (classification change)

Under Canadian GAAP, costs of arranging debt financing, premiums and discounts were netted against long-term debt. Under US GAAP, costs of arranging debt financing are included in "Deferred debt costs" as part of "Other long-term assets", and net unamortized premiums are included in "Net unamortized debt premiums" as part of "Other long-term liabilities".

At January 1, 2011 and December 31, 2011, the effect on the Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Deferred debt costs	11	11
Other long-term liabilities:		
Net unamortized debt premiums	13	11
Long-term debt	(2)	-

B. Post-Retirement and Post-Employment Benefits (measurement change)

Under Canadian GAAP, the Distribution Business disclosed, but was not required to recognize, the net unfunded status of post-retirement and post-employment benefit obligations on the Balance Sheets. Under US GAAP, the Distribution Business recognized the unfunded status of post-retirement and post-employment benefit obligations on the Balance Sheets with an offset to associated regulatory assets for the transitional fair value adjustments as the incremental obligations are expected to be recovered through future rates charged to customers. The deferred tax assets and liabilities arising on recognition of incremental post-retirement and post-employment benefit obligations and the associated regulatory assets offset each other, with no material impact on the Statements of Operations and Comprehensive Income. In the absence of regulatory accounting, the related tax impact on the opening transitional adjustments would result in the recognition of deferred tax assets of $22 million on January 1, 2011 and $18 million on December 31, 2011.

At January 1, 2011 and December 31, 2011, the effect on the Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Regulatory assets	86	70
Other long-term liabilities:		
Post-retirement and post-employment benefit liability	(86)	(70)

C. Derivative Instruments (classification change)

Under Canadian GAAP, the Distribution Business classified its derivative instruments in designated hedging relationships and in economic hedging relationships under the category of "Other assets" on the Balance Sheets. Under US GAAP, the Distribution Business has included these balances in "Derivative instruments".

At January 1, 2011 and December 31, 2011, the effect on the Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Derivative instruments	1	9
Other	(1)	(9)

D. Accounts Payable (classification change)

Under Canadian GAAP, trade and non-trade payables were disclosed as "Accounts payable and accrued charges". Under US GAAP, trade payables are recognized in "Accounts payable" and non-trade payables are recognized in "Accrued liabilities".

At January 1, 2011 and December 31, 2011, the effect on the Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Current liabilities:		
Accounts payable	43	49
Accrued liabilities	518	643
Accounts payable and accrued charges	(561)	(692)

23. COMPARATIVE FIGURES

The comparative Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2012 Financial Statements.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2011

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying financial statements of the Distribution Business (a business of Hydro One Networks Inc.), which comprise the balance sheet as at December 31, 2011, the statement of operations and comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to these financial statements.

Management's Responsibility for the Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these financial statements in accordance with basis of accounting in Note 2 to these financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these financial statements in the circumstances, 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 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 the Distribution Business (a business of Hydro One Networks Inc.) as at December 31, 2011 and the results of its operations and its cash flows for the year then ended in accordance with basis of accounting as set out in Note 2 to these financial statements.

Basis of Accounting and Restriction on Use

Without modifying our opinion, we draw attention to Note 2 to these financial statement, which describes the basis of accounting and composition of the Hydro One Networks Inc. that comprise Distribution Business. In particular, in preparing these financial statements, corporate long-term debt, shared functions and services costs and payments in lieu of corporate income taxes have been allocated to the Distribution Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to these financial statements. As a result of this basis of accounting, these financial statements may not necessarily be identical to the financial position, results of operations and cash flows that would have resulted had the Distribution Business (a business of Hydro One Networks Inc.) historically operated on a stand-alone basis. These financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, these financial statements may not be suitable for another purpose. Our report is intended solely for Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Accountants, Licensed Public Accountants
Toronto, Canada
April 2, 2012

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Years ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Revenues		
Energy sales	3,398	3,157
Rural rate protection *(Note 16)*	125	125
Other	46	46
	3,569	3,328
Costs		
Purchased power *(Note 16)*	2,285	2,156
Operation, maintenance and administration *(Note 16)*	555	554
Depreciation and amortization *(Note 3)*	287	277
	3,127	2,987
Income before financing charges and provision for payments in lieu of corporate income taxes	442	341
Financing charges *(Notes 4 and 16)*	140	139
Income before provision for payments in lieu of corporate income taxes	302	202
Provision for payments in lieu of corporate income taxes *(Notes 5 and 16)*	66	8
Net income and comprehensive income	236	194

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2011**	**2010**
Assets		
Current assets:		
Inter-company demand facility *(Note 16)*	141	86
Accounts receivable (net of allowance for doubtful accounts - $15 million; 2010 - $22 million) *(Note 16)*	744	710
Regulatory assets *(Note 8)*	9	25
Materials and supplies	4	5
Future income tax assets *(Note 5)*	8	12
Other	7	2
	913	840
Fixed assets *(Note 6)*:		
Fixed assets in service	7,863	7,397
Less: accumulated depreciation	2,870	2,690
	4,993	4707
Construction in progress	293	269
Future use land, components and spares	39	39
	5,325	5,015
Other long-term assets:		
Regulatory assets *(Note 8)*	361	338
Intangible assets (net of accumulated amortization) *(Note 7)*	108	76
Goodwill	73	73
Other	9	2
	551	489
Total assets	6,789	6,344

See accompanying notes to Financial Statements.

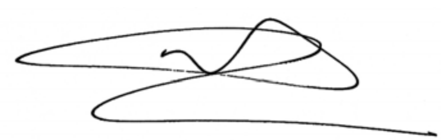
HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2011**	**2010**
Liabilities		
Current liabilities:		
Accounts payable and accrued charges *(Notes 13 and 16)*	692	561
Regulatory liabilities *(Note 8)*	16	47
Accrued interest	31	31
Long-term debt payable within one year *(Notes 9, 10 and 16)*	324	176
	1,063	815
Long-term debt *(Notes 9, 10 and 16)*	2,565	2,658
Other long-term liabilities:		
Employee future benefits other than pension *(Note 12)*	576	543
Environmental liabilities *(Note 13)*	134	157
Future income tax liabilities *(Note 5)*	171	154
Regulatory liabilities *(Note 8)*	105	34
Asset retirement obligations *(Note 14)*	3	3
Long-term accounts payable and other liabilities	4	4
	993	895
Total liabilities	4,621	4,368
Contingencies and commitments *(Notes 18 and 19)*		
Excess of assets over liabilities *(Notes 11 and 15)*	2,168	1,976
Total liabilities and excess of assets over liabilities	6,789	6,344

See accompanying notes to Financial Statements.

On behalf of the Board:

Laura Formusa
Chair



Sandy Struthers
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS

Years ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Operating activities		
Net income	236	194
Environmental expenditures	(8)	(9)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	242	234
Regulatory asset and liability accounts	40	3
Future income taxes	(9)	(9)
Gain on interest rate swap agreements	(3)	(5)
Other	4	-
	502	408
Changes in non-cash balances related to operations *(Note 17)*	128	58
Net cash from operating activities	630	466
Financing activities		
Allocated long-term debt issued	225	500
Allocated long-term debt retired	(176)	(197)
Payments to Hydro One to finance dividends	(45)	(7)
Other	(1)	-
Net cash from financing activities	3	296
Investing activities		
Capital expenditures		
Fixed assets	(539)	(585)
Intangible assets	(57)	(5)
	(596)	(590)
Other assets	18	20
Net cash used in investing activities	(578)	(570)
Net change in inter-company demand facility	55	192
Inter-company demand facility, January 1	86	(106)
Inter-company demand facility, December 31	141	86

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
NOTES TO FINANCIAL STATEMENTS

1. DESCRIPTION OF THE DISTRIBUTION BUSINESS

Hydro One Inc. (Hydro One) 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).

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These financial statements have been prepared in accordance with the accounting policies summarized below. These policies are consistent with Canadian generally accepted accounting principles (GAAP) as contained in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook - Accounting. These financial statements have been prepared for the specific use of the OEB. Consolidated financial statements of Hydro One for the year ended December 31, 2011 have been prepared and are publicly available.

These financial statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Distribution Business on a basis approved by the OEB. The financial statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of that business. As a result of this basis of accounting, these financial statements may not necessarily be identical to the financial position and results of operations and cash flows that would have resulted had the Distribution Business historically operated on a stand-alone basis.

These financial statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs are allocated to the Distribution Business on a fully-allocated basis, consistent with OEB-approved independent studies. Payments in lieu of corporate income taxes (PILs) have been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Distribution Business was a separate taxpaying entity. Certain other amounts presented in these financial statements represent allocations subject to review and approval by the OEB.

Rate-setting

The rates of the Company's electricity Distribution Business are subject to regulation by the OEB.

In January 2009, Hydro One Networks filed an updated incentive regulation distribution rate application for 2009 rates on the basis of the OEB's third-generation Incentive Regulation Mechanism (IRM) process, which adjusts previously established 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 into service beyond a prescribed threshold. On May 13, 2009, the OEB released its decision with reasons approving the basic IRM increase and a rate adder 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.
In 2009, Hydro One Networks filed a cost-of-service rate application with the OEB for 2010 and 2011 distribution

rates. This reflected 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 Green Energy Act (GEA). The application sought OEB approval of distribution 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 with reasons 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 the disposition of certain distribution-related regulatory 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 meter amounts. The OEB ordered that the approved balances be aggregated into a single regulatory liability account (Rider 6) to be recovered over a 20-month period from May 1, 2010 to December 31, 2011.

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 Distribution Business' 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 Distribution Business has recorded regulatory liabilities, which represent amounts incurred in different periods than would be the case had the Distribution Business 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 its results of operations in the period that the assessment is made. The specific regulatory assets and liabilities recognized at December 31, 2011 are disclosed in Note 8.

Revenue Recognition

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's Distribution Business estimates revenue for each monthly 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, 2011 amounted to $513 million (2010 - $462 million).

Revenue also includes an amount relating to rate protection for rural residential 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 consumers by reducing the electricity rates that would otherwise apply.

Revenue also includes amounts 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 Networks 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 income.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that they are more likely than not to be realized from taxable income 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 re-evaluated 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 income.

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 and, implicitly, by the regulated businesses of these subsidiaries. The inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

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.

Fixed assets in service consist of 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.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication, Administration and Service

Communication, administration and service assets include telecommunications equipment, towers, buildings associated with communications assets, administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include amounts incurred to acquire land rights and other access rights.

Intangible Assets

Intangible assets primarily represent computer applications software assets. These assets are capitalized at cost, which comprises purchased software, labour and consulting, engineering, overheads and the OEB-approved allowance for funds used during construction applicable to capital development.

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 (2011 - 4.20%; 2010 - 4.34%).

Depreciation and Amortization

The capital costs of fixed assets and intangible assets 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 and Canadian GAAP. The last review resulted in changes to rates effective January 1, 2007. A summary of depreciation rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Distribution	1% - 5%	2%
Communication, Administration and Service	1% - 15%	8%
Easements	1%	1%

Intangible assets are primarily included within the communication, 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 finite life easements are based on their contract lives. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of fixed assets or intangible 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 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 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 results of operations. The Company has determined that goodwill is not impaired.

Financial Instruments

Recognition and measurement

All financial instruments are classified into one of the following five categories: held-to-maturity investments; loans and receivables; held-for-trading; other assets and liabilities; or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the Balance Sheets except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in other comprehensive income (OCI) until the instrument is derecognized or impaired. The Distribution Business has classified its financial instruments as follows:

Assets / Liabilities	Classification	Measurement
Accounts receivable	Loans and receivables	Amortized cost
Inter-company demand facility	Other assets	Amortized cost
Accounts payable	Other liabilities	Amortized cost
Long-term debt (unless otherwise specified)	Other liabilities	Amortized cost
Fixed-to-floating interest-rate swaps	Not classified	Fair value
$100 million of a $250 million note matured on March 3, 2011	Not classified	Fair value
$100 million of a $500 million note due November 19, 2014	Not classified	Fair value
$100 million of a $500 million note due September 11, 2015	Not classified	Fair value
Floating-to-fixed interest-rate swaps	Held-for-trading	Fair value

In March 2008, January 2010 and January 2011, Hydro One issued notes for long-term financing under its Medium-Term Note (MTN) Program in the amounts of $250 million, $500 million and $250 million, respectively. The first $250 million issue, $250 million of the $500 million issue and the second $250 million issue were mirrored down to Hydro One Networks through the issuance of inter-company debt with $100 million of each issue allocated to the Distribution Business. These amounts were designated as part of a hedging relationship. As at December 31, 2011, derivative instruments include fixed-to-floating interest-rate swap agreements with a total amount of $200 million to convert the $200 million of fixed rate debt into three-month variable-rate debt as well as floating-to-fixed interest-rate swap agreements with a total amount of $220 million that locks in the rate resets on $220 million floating rate debt for 2012. These long-term debt issues, and related hedging instruments, are not classified.

All financial instrument transactions are recorded at trade date.

Discounts and Premiums on Debt

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

Transaction Costs

Transaction costs related to Hydro One Networks' 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 and then amortized over the expected life of the instrument using the effective interest method.

Derivative Instruments and Hedge Accounting

All derivative instruments, including embedded derivatives, are carried at fair value on the Balance Sheets 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. The Company does not have any significant embedded derivatives in contracts that require separate accounting and disclosure.

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.

Hydro One periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, Hydro One 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. Hydro One 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. These hedges are mirrored by the Company.

Comprehensive Income

Comprehensive income is comprised of the Distribution Business' net income and OCI. OCI includes the amortization of the Distribution Business' share of the Company's net unamortized hedging losses on the Company's proportionate share of Hydro One's discounted cash flow hedges, and the change in fair value on the Company's proportionate share of 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 allocated hedged debt.

Financial Instrument Disclosures

All financial instruments measured at fair value are categorized into one of the three levels of hierarchy. Each level is based on the transparency of the inputs used to measure the fair values of assets and liabilities:

Level 1 – inputs are unadjusted quoted prices of identical instruments in an active market;
Level 2 – inputs do not have quoted prices but are observable for the asset or liability, either directly or indirectly; and
Level 3 – inputs that are not based on observable market data.

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 and its subsidiaries 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 and intangible assets.

Environmental Costs

The Distribution Business records a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil 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. The Distribution Business reviews its estimates of future environmental expenditures on an ongoing basis.

Asset Retirement Obligations

When required by force of law or regulation, the Distribution Business 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 Distribution Business 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 Distribution Business' 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 Distribution Business 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. The asset retirement obligations recorded to date are primarily related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of the Company's facilities.

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

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 1, 2011, the Company submitted an application to the OEB asking for approval to adopt US GAAP as the approved basis for rate-setting and regulatory accounting and reporting for its Distribution Business in preference to modified IFRS.

3. DEPRECIATION AND AMORTIZATION

Years ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Depreciation of fixed assets in service	212	196
Amortization of intangible assets	22	21
Fixed asset removal costs	45	43
Amortization of regulatory and other assets	8	17
	287	277

4. FINANCING CHARGES

Years ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Interest on long-term debt payable *(Note 16)*	152	150
Other	1	(1)
Less: Interest capitalized on construction and development in progress	(11)	(9)
Interest on inter-company demand facility	(2)	(1)
	140	139

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 millions)	**2011**	**2010**
Income before provision for PILs	302	202
Federal and Ontario statutory income tax rate	28.25%	31.00%
Provision for PILs at statutory rate	85	63
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Pension contributions in excess of pension expense	(10)	(11)
Overheads capitalized for accounting but deducted for tax purposes	(5)	(5)
Capital cost allowance in excess of depreciation and amortization	(4)	(33)
Interest capitalized for accounting but deducted for tax purposes	(3)	(3)
Employee future benefits other than pension expense in excess of cash payments	3	2
Environmental expenditures	(2)	(3)
Other	1	(3)
Net temporary differences	(20)	(56)
Net permanent differences	1	1
Total income tax provision for PILs	66	8
Current income tax provision for PILs	75	17
Future income tax provision for PILs	(9)	(9)
Total income tax provision for PILs	66	8
Effective income tax rate	21.85%	3.96%

The provision for payments in lieu of current income taxes of $75 million represents the amount payable to the OEFC with respect to current year income. The outstanding balance due to the OEFC at December 31, 2011 is $50 million (2010 - $9 million).

The payments in lieu of future income taxes recoverable of $9 million reflects the decrease in the liability for payments in lieu of future income taxes that are not expected to be recovered from the Distribution Business' customers through future rates.

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 the Distribution Business' assets and liabilities. The tax effects of these differences are as follows:

December 31 (Canadian dollars in millions)	**2011**	**2010**
Future Income Tax Assets		
Employee future benefits other than pension expense in excess of cash payments	200	189
Environmental expenditures	36	42
Other	1	3
Total future income tax assets	237	234
Less: current portion	10	15
	227	219

December 31 (Canadian dollars in millions)	**2011**	**2010**
Current future income tax assets	10	15
Current future income tax liabilities	(2)	(3)
Net current future income tax assets	8	12

Future Income Tax Liabilities		
Capital cost allowance in excess of depreciation and amortization	374	334
Amounts paid but not recognized for accounting purposes	19	35
Goodwill	7	6
Other	-	1
Total future income tax liabilities	400	376
Less: current portion	2	3
	398	373

Long-term future income tax assets	227	219
Long-term future income tax liabilities	(398)	(373)
Net long-term future income tax liabilities	(171)	(154)

The increase in the liability for payments in lieu of future income taxes that is expected to be recovered from customers through future rates has resulted in an increase in regulatory assets.

6. FIXED ASSETS

December 31 (Canadian dollars in millions)	Cost	Accumulated Depreciation	Construction in Progress	Total
2011				
Distribution	7,090	2,440	243	4,893
Communication, administration and service	804	426	50	428
Easements	8	4	-	4
	7,902	2,870	293	5,325
2010				
Distribution	6,744	2,301	252	4,695
Communication, administration and service	684	385	17	316
Easements	8	4	-	4
	7,436	2,690	269	5,015

Financing costs are capitalized on fixed assets under construction using the OEB’s approved allowance for funds used during construction on regulated assets and were $10 million in 2011 (2010 - $9 million).

7. INTANGIBLE ASSETS

December 31 (Canadian dollars in millions)	Cost	Accumulated Amortization	Development in Progress	Total
2011				
Computer applications software	217	153	44	108
Other assets	1	1	-	-
	218	154	44	108

December 31 (Canadian dollars in millions)	Cost	Accumulated Amortization	Development in Progress	Total
2010				
Computer applications software	202	130	4	76
Other assets	1	1	-	-
	203	131	4	76

Financing costs are capitalized on intangible assets under development using the OEB's approved allowance for funds used during construction on regulated assets and were $1 million in 2011 (2010 - $nil).

8. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 (Canadian dollars in millions)	**2011**	**2010**
Regulatory assets:		
Future income tax regulatory asset	181	151
Environmental	142	166
Pension cost variance	29	16
Rider 2 (Regulatory asset recovery account II)	11	11
Rural and remote rate protection variance	-	7
Rider 4 (Revenue recovery account)	-	5
Other	7	7
Total regulatory assets	370	363
Less: current portion	9	25
	361	338
Regulatory liabilities:		
Rider 8	41	9
Retail settlement variance accounts	40	21
Rider 3 (Regulatory liability refund account)	9	19
Future income tax regulatory liability	7	8
Rural and remote rate protection variance	8	-
PST savings deferral	6	1
Rider 6	-	19
Other	10	4
Total regulatory liabilities	121	81
Less: current portion	16	47
	105	34

Regulatory Assets

Future Income Tax Regulatory 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 income. The Company has recognized regulatory assets and 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 established for taxes to be recovered through future rates. As a result, the Distribution Business' provision for PILs would have been higher by approximately $22 million (2010 - $28 million) including the impact of a change in substantively enacted tax rates.

Environmental

The Distribution Business 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 Distribution Business has recorded an equivalent amount as a regulatory asset. In 2011, this regulatory asset decreased by $23 million (2010 - increased by $2 million) to reflect a revaluation adjustment in the Company's PCB liability. There was no change in the land assessment and remediation (LAR) liability (2010 –$1 million decrease). 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 the Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been lower by $23 million (2010 - higher by $1 million). In addition, amortization expense in 2011 would have been lower by $8 million (2010 - $9 million) and financing charges would have been higher by $8 million (2010 - $8 million).

Pension Cost Variance

The pension cost variance account was established to track the difference between the actual pension costs incurred by the Distribution Business and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension contributions paid compared to OEB-approved amounts. In the absence of rate-regulated accounting, revenue would have been lower by $13 million in 2011 (2010 - $12 million).

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

As part of a 2006 distribution rate decision, the OEB approved the recovery of several distribution-related deferral account balances sought by the Company. RARA II includes retail settlement and cost variance amounts, distribution low-voltage service amounts and accrued interest. In the absence of rate-regulated accounting, amortization expense would have been lower by $8 million in 2010.

Rural and Remote Rate Protection Variance (RRRP)

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of the Company's Distribution Business 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 the Company in respect of the Distribution Business and the fixed entitlements defined in the regulation, and subsequent OEB rate decisions, are tracked by the Company in the RRRP variance account to be disposed of at a later date.

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. 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

Rider 8

As part of its April 9, 2010 rate decision, the OEB required the establishment of deferral accounts to capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and actual recoveries received.

Retail Settlement Variance Accounts (RSVA)

The Distribution Business has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. Hydro One Networks has accumulated a net liability in its RSVAs since December 31, 2009.

Rider 3 or RLRA

The OEB's December 18, 2008 decision approved certain distribution-related deferral account balances sought by the Company in its application including RSVA amounts, deferred impact of tax rate changes, OEB costs and smart meter amounts. 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.

PST savings deferral

The Company is required to record the impact from the implementation of an HST sales tax regime on July 1, 2010. The variance amounts recognized in the account reflect Provincial Sales Tax (PST) amounts in approved revenue requirements after the implementation of the HST. These amounts will be refunded to ratepayers in future years.

Rider 6

As part of the April 9, 2010 rate decision, the OEB approved for disposal certain distribution-related deferral account balances, including retail settlement variance accounts, the Regulatory Asset Recovery Account I, retail cost variance accounts and smart meter amounts. The OEB ordered that the balances approved for recovery be aggregated into a single regulatory account (Rider 6) to be recovered over a 20-month period from May 1, 2010 to December 31, 2011.

9. DEBT

Debt represents the Distribution Business' share of various notes payable by Hydro One Networks to Hydro One.

December 31 (Canadian dollars in millions)	**2011**	**2010**
Long-term debt	2,880	2,831
Add: Unrealized marked-to-market loss[1]	9	2
Less: Long-term debt payable within one year	(324)	(176)
Net unamortized premiums	11	12
Unamortized debt issuance costs	(11)	(11)
	2,565	2,658

[1] The unrealized marked-to-market loss relates to the $100 million note which matured March 3, 2011; $100 million of the $175 million note maturing November 19, 2014 and $100 million of the $200 million note maturing September 11, 2015, which are accounted for as fair value hedges. The unrealized marked-to-market loss is offset by a $9 million (2010 - $2 million) unrealized gain on the related fixed-to-floating interest rate swap agreements.

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, 2011 is as follows:

(Canadian dollars in millions)	**Derivatives Used for Hedging**	**Other Financial Instruments Used for Hedging**	**Loans and Receivables**	**Other Financial Assets and Liabilities**
Financial Assets				
Inter-company demand facility	-	-	-	141
Accounts receivable	-	-	744	-
Other assets	9	-	-	-
Financial Liabilities				
Accounts payable and accrued charges[1]	-	-	-	641
Long-term debt	-	209	-	2,680

[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 Distribution Business, 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)	**2011**		**2010**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	2,880	3,389	2,831	3,114

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the amounts which are 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 Hydro One could in the future decide to issue foreign currency denominated debt which could be mirrored through parental issuance to the Company. This debt will be hedged back to Canadian dollars consistent with Hydro One's risk management policy. The Company is exposed to fluctuations in interest rates as the regulated rate of return for the Company's Distribution Business 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 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, 2011, 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, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2011, there was no significant balance of accounts receivable due from any single customer.

In the year, the Distribution Business' provision for bad debts was $15 million (2010 - $22 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, 2011, approximately 3% of the Distribution Business' 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 counterparties consistent with Hydro One'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 counterparties. The Company's credit risk for accounts receivable is limited to the carrying amount on the Balance Sheets.

Hydro One uses derivative financial instruments to manage interest rate risk. Hydro One, and the Company, may enter into derivative agreements such as forward interest rate 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, 2011.

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 from Hydro One and funds from 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 $641 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 $324 million. Interest payments over the next twelve months on the Distribution Business' outstanding debt amount to $150 million.

As at December 31, 2011, the Distribution Business' share of the long-term debt of Hydro One Networks to Hydro One is $2,880 million and the required future interest payments are $2,408 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	324	150	5.8
2 years	230	131	5.0
3 years	175	120	3.2
4 years	220	114	2.9
5 years	180	104	4.7
	1,129	619	4.5
6 – 10 years	315	450	4.9
Over 10 years	1,436	1,339	5.9
	2,880	2,408	5.2

11. CAPITAL MANAGEMENT

The Distribution Business's objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB as being appropriate for all distributors in its December 20, 2006 Cost of Capital Report. This deemed capital structure is 60% debt and 40% common equity.

The Distribution Business considers its capital structure to consist of excess assets over liabilities, long-term debt, and the inter-company demand facility. The following table summarizes this capital structure:

(Canadian dollars in millions)	**2011**	**2010**
Long-term debt payable within one year	324	176
Less: Inter-company demand facility	141	86
	183	90
Long-term debt	2,565	2,658
Excess of assets over liabilities	2,168	1,976
Total capital	4,916	4,724

12. 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 accrual 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 employees represented by the 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 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 related to a partial plan wind-up of $4 million. 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.

For Hydro One, the actuarial present value at December 31, 2011 of the accrued pension benefits, based on a projection of the valuation at December 31, 2011, was estimated to be $5,461 million (2010 - $4,996 million). Pension plan assets available for these benefits were $4,682 million (2010 - $4,699 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2011, $33 million of employee future benefits other than pension costs were charged to the results of operations of the Distribution Business (2010 - $28 million), and $23 million was capitalized as part of the cost of fixed and intangible assets (2010 - $19 million). Benefits paid were $23 million (2010 - $23 million). The liability associated with employee future benefits other than pension for the Distribution Business at December 31, 2011 was $598 million (2010 - $565 million), including the current portion.

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.

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	Polychlorinated Biphenyls (PCB)	Land Assessment and Remediation (LAR)	Total
2011			
Environmental liabilities, January 1	135	31	166
Interest accretion	7	1	8
Expenditures	(3)	(5)	(8)
Revaluation adjustment	(23)	-	(23)
Environmental liabilities, December 31	116	27	143
Less: current portion	5	4	9
	111	23	134
2010			
Environmental liabilities, January 1	130	36	166
Interest accretion	7	1	8
Expenditures	(4)	(5)	(9)
Revaluation adjustment	2	(1)	1
Environmental liabilities, December 31	135	31	166
Less: current portion	5	4	9
	130	27	157

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2011 and in total thereafter are as follows: 2012 - $9 million; 2013 - $9 million; 2014 - $22 million; 2015 - $19 million; 2016 - $18 million and thereafter - $89 million. Of the total estimated future expenditures, $138 million relate to PCB (2010 - $156 million) and $28 million to LAR (2010 - $33 million).

Consistent with the Company's accounting policy for environmental costs, the Distribution Business 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.

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, the Company 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 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.

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 Distribution Business' 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 Distribution Business' 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 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 the obligations were first recorded.

14. ASSET RETIREMENT OBLIGATIONS

Consistent with its accounting policy for asset retirement obligations, Hydro One Networks records a liability for the present value of the estimated future expenditures associated with the retirement of tangible long-lived assets that it 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.

The Company 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. In 2010, 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 present value of the estimated future expenditures is $3 million. The amount of interest recorded is nominal and there have been no expenditures associated with this obligation.

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 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.

15. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of preferred shares and common shares.

16. RELATED PARTY TRANSACTIONS

The Province and Successor Corporations of Ontario Hydro

The Province, OEFC, IESO, Ontario Power Authority (OPA) and Ontario Power Generation Inc. (OPG) are related parties of the Company and its Distribution Business. In addition, the OEB is related by virtue of its status as a Provincial Crown Corporation. The OEB is a self-financing and self-sufficient regulatory organization that carries out independent regulation for Ontario's energy sector, including Hydro One's regulated Distribution Business. Transactions between these parties and the Distribution Business were as follows:

The Distribution Business received amounts for rural rate protection from the IESO. Revenues include $125 million related to this program in each of 2011 and 2010. In 2011, the Distribution Business purchased power in the amount of $2,057 million (2010 - $2,042 million) from the IESO-administered electricity market, $16 million (2010 - $19 million) from OPG and $10 million (2010 - $13 million) from the 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 2011, the Distribution Business incurred $7 million (2010 - $7 million) in OEB fees.

The Company has service level agreements with Ontario Hydro's successor corporations, primarily OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Operation, maintenance and administration costs related to the purchase of services from these successor corporations were less than $1 million in each of 2011 and 2010.

The OPA funds some of the Company's Conservation and Demand Management (CDM) programs. The funding includes program costs, incentives and management fees and bonuses. In 2011, the Distribution Business received $38 million (2010 - $30 million) from the OPA in respect of the CDM programs. Revenues include $3 million of unregulated incentive revenue from the OPA in respect of CDM programs in both 2011 and 2010.

The PILs, property taxes and capital taxes of the Distribution Business were paid or payable by the Company to the OEFC (Note 5).

Hydro One and Subsidiaries

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

The Company has entered into various agreements with Hydro One and its subsidiaries related to the provision of corporate functions and services, supply management, computer support and operational services such as environmental, forestry and line services. Revenues of the Distribution Business include $2 million (2010 - $2 million) related to the provision of services to Hydro One and its subsidiaries. Operation, maintenance and administration costs of the Distribution Business include $10 million (2010 - $8 million) related to the purchase of services from Hydro One and its subsidiaries.

The Company's debt, including the portion allocated to the Distribution Business, is due to Hydro One. Financing charges of the Distribution Business include interest expense on this debt in the amount of $152 million (2010 - $150 million). In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One. Financing charges of the Distribution Business are net of interest earned on this facility in the amount of $2 million (2010 - $1 million).

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)	**2011**	**2010**
Accounts receivable	23	1
Accounts payable and accrued charges	(237)	(208)

Included in accounts payable and accrued charges are amounts owing to the IESO, OEFC, OPG in respect of power purchases of $182 million (2010 - $193 million).

17. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Years ended December 31 (Canadian dollars in millions)	**2011**	**2010**
Accounts receivable increase	(31)	(40)
Materials and supplies decrease	1	1
Accounts payable and accrued charges increase	131	63
Accrued interest increase	-	3
Long-term accounts payable and other liabilities decrease	-	(1)
Employee future benefits other than pension increase	33	22
Other	(6)	10
	128	58

Supplementary information:		
Interest paid	152	149
Payments in lieu of corporate income taxes	31	16

18. CONTINGENCIES

The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Company's Distribution Business are available for the satisfaction of the debts, contingent liabilities and commitments of the Company and Hydro One.

19. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the net assets of the Distribution Business are available to satisfy these commitments.

20. SUBSEQUENT EVENTS

On January 13, 2012, Hydro One issued $300 million in 3.20% notes under its MTN program with a maturity date of January 13, 2022. On the same date, Hydro One Networks issued 3.22% notes payable to Hydro One in the amount of $280 million, with the same maturity date. The Distribution Business' share of the offering was $126 million.

On March 23, 2012, the OEB approved Hydro One Networks' request to adopt US GAAP as the basis for regulatory accounting and reporting in its Distribution Business, consistent with an earlier approval given to its Transmission Business. This decision aligns Hydro One Networks' regulatory reporting framework with that approved for Hydro One Inc..

21. 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.

Norfolk Power Distribution Inc.

Financial Statements

December 31, 2012

Norfolk Power Distribution Inc.

Index to Financial Statements

December 31, 2012

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Norfolk Power Distribution Inc.

We have audited the accompanying financial statements of Norfolk Power Distribution Inc., which comprise the balance sheet as at December 31, 2012 and the statements of operations, retained earnings and cash flow for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Norfolk Power Distribution Inc. as at December 31, 2012, and the results of its operations and its cash flow for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

Chartered Accountants
Licensed Public Accountants

April 16, 2013
Simcoe, Ontario

Management's Responsibility for Financial Reporting

The financial statements of Norfolk Power Distribution Inc. have been prepared in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. These statements include certain amounts based on management's estimates and judgments. Management has determined such amounts based on a reasonable basis in order to ensure that the financial statements are presented fairly in all material respects.

The integrity and reliability of Norfolk Power Distribution Inc.'s reporting systems are achieved through the use of formal policies and procedures, the careful selection of employees and an appropriate division of responsibilities. These systems are designed to provide reasonable assurance that the financial information is reliable and accurate.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit and Finance Committee. The Committee is appointed by the Board and meets periodically with management and the shareholder's auditors to review significant accounting, reporting and internal control matters. Following its review of the financial statements and discussions with the auditors, the Audit and Finance Committee reports to the Board of Directors prior to its approval of the financial statements. The Committee also considers, for review by the Board and approval by the shareholder, the engagement or re-appointment of the external auditors.

The financial statements have been audited on behalf of the shareholder by Millard, Rouse & Rosebrugh LLP , in accordance with generally accepted auditing standards.

Jody McEachran, Interim President & CEO

J.J. Knott, Board of Directors Chair

Frank Casey, Audit and Finance Committee Chair

Norfolk Power Distribution Inc.

Balance Sheet

As at December 31, 2012

	2012	2011
ASSETS		
Current		
Cash	$ 895,049	$ 3,142,592
Accounts receivable	5,188,861	4,253,675
Unbilled revenue	4,062,418	3,953,201
Due from associated companies *(Note 5)*	39,571	-
Income taxes recoverable	-	729,939
Inventory	575,141	533,619
Prepaid expenses	390,613	395,003
	11,151,653	13,008,029
Property and equipment *(Note 6)*	53,859,407	50,122,402
Regulatory assets *(Note 7)*	1,249,684	6,389,112
Future income taxes	927,283	897,781
	$ 67,188,027	$ 70,417,324
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable	$ 5,436,838	$ 6,707,499
Due to associated companies	-	134,166
Income taxes payable	126,229	-
Current portion of customer deposits	50,000	115,000
Current portion of long term debt	1,172,547	966,967
	6,785,614	7,923,632
Regulatory liabilities *(Note 7)*	2,959,742	4,259,651
Customer deposits *(Note 8)*	51,547	20,916
Long term debt *(Note 9)*	26,997,457	28,170,004
Post employment benefits *(Note 10)*	956,214	878,082
	37,750,574	41,252,285
Shareholder's equity		
Share capital *(Note 11)*	22,768,898	22,768,898
Retained earnings	6,668,555	6,396,141
	29,437,453	29,165,039
	$ 67,188,027	$ 70,417,324

See accompanying notes

Norfolk Power Distribution Inc.
Statement of Retained Earnings
Year ended December 31, 2012

	2012	2011
Retained earnings - beginning of year	**$ 6,396,141**	$ 4,885,948
Net income for the year	**1,472,414**	2,310,193
	7,868,555	7,196,141
Dividends	**(1,200,000)**	(800,000)
RETAINED EARNINGS - END OF YEAR	**$ 6,668,555**	$ 6,396,141

See accompanying notes

Norfolk Power Distribution Inc.

Statement of Operations

Year ended December 31, 2012

	2012	2011
REVENUE		
Energy sales	**$ 34,011,357**	$ 32,764,997
Distribution services	**11,424,687**	11,022,242
Other	**660,823**	667,005
	46,096,867	44,454,244
Cost of power	**34,011,357**	32,764,997
Distribution revenue	**12,085,510**	11,689,247
EXPENSES		
Distribution system - operation and maintenance	**2,245,690**	2,191,894
Billing and collecting	**1,251,412**	1,008,136
Community relations	**30,932**	48,570
Administrative and general expense	**2,772,838**	1,553,796
Taxes other than amounts in lieu of corporate taxes	**57,594**	36,435
	6,358,466	4,838,831
Income before amortization, interest and income taxes	**5,727,044**	6,850,416
Amortization *(Note 12)*	**2,308,080**	2,625,509
Interest	**1,402,550**	1,638,214
	3,710,630	4,263,723
Income before income taxes	**2,016,414**	2,586,693
Income taxes *(Note 13)*	**544,000**	276,500
NET INCOME FOR THE YEAR	**$ 1,472,414**	$ 2,310,193

See accompanying notes

Norfolk Power Distribution Inc.

Statement of Cash Flow

Year ended December 31, 2012

	2012	2011
OPERATING ACTIVITIES		
Net income for the year	**$ 1,472,414**	$ 2,310,193
Items not affecting cash:		
Amortization *(Note 12)*	**2,408,371**	2,949,756
Future income taxes	**(29,502)**	317,469
Post employment benefits	**78,132**	10,282
Gain on disposal of property and equipment	**(6,600)**	(13,890)
	3,922,815	5,573,810
Changes in non-cash working capital:		
Accounts receivable	**(935,186)**	(62,253)
Unbilled revenue	**(109,217)**	572,848
Amount due from (to) associated companies	**(173,735)**	216,647
Income taxes recoverable	**856,168**	(354,912)
Inventory	**(41,522)**	16,059
Prepaid expenses	**4,390**	(75,181)
Accounts payable	**(1,270,661)**	418,205
	(1,669,763)	731,413
Cash flow from operating activities	**2,253,052**	6,305,223
INVESTING ACTIVITIES		
Purchase of property and equipment	**(6,997,779)**	(5,053,411)
Proceeds on disposal of property and equipment	**272,787**	46,800
Contributions in aid of construction	**586,214**	1,338,253
Net change in regulatory assets and liabilities	**3,839,519**	(1,008,197)
Cash flow used by investing activities	**(2,299,259)**	(4,676,555)
FINANCING ACTIVITIES		
Repayment of customer deposits	**(34,369)**	(104,447)
Demand loan financing (repaid)	**-**	(3,500,000)
Loans and debentures financing received	**-**	6,000,000
Repayment of loans and debentures	**(966,967)**	(918,150)
Dividends declared	**(1,200,000)**	(800,000)
Cash flow from (used by) financing activities	**(2,201,336)**	677,403
INCREASE (DECREASE) IN CASH	**(2,247,543)**	2,306,071
Cash - beginning of year	**3,142,592**	836,521
CASH - END OF YEAR	**$ 895,049**	$ 3,142,592

See accompanying notes

1. NATURE OF ACTIVITIES

On November 1, 2000, Norfolk Power Inc. was incorporated under the Ontario Business Corporations Act, along with its two wholly owned subsidiary companies, Norfolk Power Distribution Inc. and Norfolk Energy Inc. Norfolk Power Distribution Inc. provides regulated electricity distribution services. Norfolk Energy Inc. provides home comfort rentals, conservation innovation, high-speed telecommunication fibre optics and other energy services.

As the sole shareholder of Norfolk Power Distribution Inc.'s parent company (Norfolk Power Inc.), Norfolk County is considered a related party. All transactions with Norfolk County are conducted within the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

Norfolk Power Distribution Inc. is a rate-regulated enterprise and Norfolk Energy Inc. is a non-rate-regulated enterprise. The difference is rate-regulated enterprises have policies that have accounting treatments differing from Canadian generally accepted accounting principles (GAAP) for enterprises operating in a non-rate-regulated environment, this is discussed in further detail in note 3.

Norfolk Power Inc. consolidated financial statements have also been prepared separately that include the accounts of Norfolk Power Inc., Norfolk Power Distribution Inc. and Norfolk Energy Inc.

2. REGULATION

In April 1999, the government of Ontario began restructuring Ontario's electricity industry. Under regulations passed pursuant to the restructuring, the Company and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator (IESO) and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board (OEB).

The OEB has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified account records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, and ensuring that electricity distribution companies fulfills their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future.

(continues)

2. REGULATION *(continued)*

The Company is required to charge its customers for the following amounts (all of which, other than distribution charges, represent a pass through of amounts payable to third parties):

1. *Distribution Charges.* Distribution charges are designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB-allowed rate of return. Distribution charges are regulated by the OEB and typically comprise of a fixed charge and a usage-based (consumption) charge.

   The volume of electricity consumed by the Company's customers during any period is governed by events largely outside the Company's control, principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity.

2. *Electricity Price and Related Regulated Adjustments.* The electricity price and related regulated adjustments represent a pass through of the commodity cost of electricity.

3. *Retail Transmission Rate.* The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

4. *Wholesale Market Service Charge.* The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

The Company's electricity distribution rates are typically effective from May 1 to April 30 of the following year. Accordingly, for January 1, 2012 to April 30, 2012, distribution revenue was based on the rates approved in 2011. Distribution revenue for the period from May 1, 2012 to December 31, 2012 was based on the distribution rates approved in 2012.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements of Norfolk Power Distribution Inc. have been prepared in accordance with Canadian GAAP, including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" (AP Handbook) and reflect the significant accounting policies summarized below:

Regulation

The following three regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

The OEB has the general authority to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in the timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable in the future from 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 recovered for specific expenditures in excess of costs incurred by the Company. These liabilities are expected to be settled with future rate adjustments. Specific regulatory assets and liabilities are disclosed in note 7.

Contributions in aid of construction

Capital contributions received from outside sources are used to finance additions to property and equipment of the Company. According to the AP Handbook, capital contributions received are treated as a reduction to property and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a reduction to amortization expense at an equivalent rate to that used for the amortization of the related property and equipment.

Future income taxes

Income taxes are reported using the tax liability method, as follows: current income tax expense is the estimated income taxes payable for the current year after any refunds or the use of losses incurred in previous years, and future income taxes reflect:

- the temporary differences between the carrying amounts of assets and liabilities for accounting purposes and the amounts used for tax purposes;
- the benefit of unutilized tax losses that will more likely than not be realized and carried forward to future years to reduce income taxes.

Future income taxes are estimated using the rates enacted by tax law and those substantively enacted for the years in which future income taxes assets are likely to be realized, or future income tax liabilities settled. The effect of a change in tax rates on future income tax assets and liabilities is included in deferred costs or recoveries of regulatory assets and liabilities in the period when the change is substantively enacted.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Revenue recognition

Energy sales and distribution services revenues are based on OEB approved rates and are recognized on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. Other revenues related to sales of other services are recognized as the services are rendered.

Changes in accounting estimates

Property and equipment

Effective January 1, 2012, the Company revised its estimates of useful lives for property and equipment following a detailed review and analysis supported by external third-party evidences. These changes in estimates have been accounted for on a prospective basis in the financial statements effective January 1, 2012. It is estimated that these changes will increase property and equipment and decrease amortization expense by approximately $500,000 for the year ended December 31, 2012.

Amortization is provided on a straight line basis for property and equipment available for use over their estimated economic lives, at the following annual rates:

	Previous	Revised
Buildings and fixtures	50 years	50 years
Transformer station equipment	40 years	20 to 45 years
Distribution station equipment	30 years	20 years
Distribution system	25 years	30 to 60 years
Meters	25 years	5 to 30 years
Vehicles	4 to 10 years	7 to 15 years
SCADA system	15 years	20 years
Computer equipment	5 years	5 years
Office furniture and equipment	10 years	10 years
Garage tools and equipment	10 years	10 years
Measurement and testing equipment	10 years	10 years
Communication equipment	10 years	10 years
Sentinel lights	15 years	15 years
Miscellaneous equipment	10 years	5 years

Effective January 1, 2012, the Company revised its estimates of burden rates of certain items of property and equipment following a detailed review and analysis of all the components included in such rates. These changes in estimates have been accounted for on a prospective basis in the financial statements effective January 1, 2012. It is estimated that these changes in estimates will decrease property and equipment and increase operating expenses by approximately $300,000 for the year ended December 31, 2012.

Property and equipment are valued at acquisition cost and include contracted services, materials, labour, engineering costs, interest and overheads. Gains or losses at retirement or disposition are credited or charged to other income in the year of disposal.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

The Company reviews property and equipment for impairment whenever events or circumstances indicate that the carrying amount is not recoverable. Any resulting impairment loss is recorded in the period in which the impairment occurs.

Inventory

Inventory consists of repair parts, supplies and materials held for operating and maintenance activities and are valued at lower of cost and net realizable value. Cost is determined using the weighted average method.

Payments in lieu of income taxes

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing taxable 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.

Pension

Employees of the Company are members of the Ontario Municipal Employees Retirement System (OMERS) which is a multi-employer public sector contributory defined benefit pension plan. The pension fund is financed by equal contributions from participating employers and employees and by the investment earnings of the fund. Contributions made by the Company on behalf of the employees amounted to approximately $350,000 (2011 - $260,000).

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. Significant areas requiring the use of management estimates relate to regulatory assets and liabilities, employee future benefits and amortization. Actual results could differ from amounts recorded in these financial statements, including changes as a result of future decisions made by the OEB or the Minister of Energy.

Interest rate swaps

The Company is party to interest rate swap agreements used to manage the exposure to market risks from changing interest rates. The Company's policy is not to utilize derivative financial instruments for trading or speculative purposes.

The Company has not hedged these agreements and the change in fair value of the swaps is reflected in the Statement of Operations. The amount recorded on the Statement of Financial Position is recorded at fair value.

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3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Financial instruments

At inception, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Gains and losses related to the measurement of financial instruments are reported in the statement of operations. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Company. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties. Further discussion of financial instruments for the Company is included in note 14 of the financial statements.

4. INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2008, the Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. Also, 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.

In 2011, the AcSB granted an optional one year deferral for IFRS adoption for entities subject to rate regulation. This decision came in light of the uncertainty created by the International Accounting Standards Board (IASB) in regard to the rate-regulated project which is assessing the potential recognition of regulatory assets and regulatory liabilities under IFRS. As such the Company will apply IFRS to its financial statements ending December 31, 2013, with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2012 for comparative purposes.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting (RRA) standard under IFRS and the potential material impact of RRA on the Company's financial statements, the Company has decided to elect the deferral of its adoption of IFRS until December 31, 2013.

As a result of these developments related to RRA under IFRS and the uncertainty regarding the impact of IFRS on the OEB electricity distribution rates application process, the Company cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and results of operation. The Company will continue to assess and evaluate the impact of this adoption.

5. DUE FROM (TO) ASSOCIATED COMPANIES

The Company is wholly owned by Norfolk Power Inc. Norfolk Power Inc. also wholly owns Norfolk Energy Inc. Transactions with these associated companies are conducted within the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

Balances owing at December 31 have no set repayment terms:

	2012	2011
Amounts owing to Norfolk Power Inc.	**$ -**	$ (206,881)
Amounts due from Norfolk Energy Inc.	**39,571**	72,715
	$ 39,571	$ (134,166)

6. PROPERTY AND EQUIPMENT

	Cost	Accumulated amortization	**2012**	2011
Distribution				
Land, land rights and easements	$ 694,044	$ -	**$ 694,044**	$ 694,044
Transformer station building	1,635,072	245,528	**1,389,544**	1,407,101
Transformer station equipment	8,912,383	971,354	**7,941,029**	8,165,150
Distribution station equipment	3,111,579	625,766	**2,485,813**	2,456,739
Poles, towers and fixtures	23,201,445	8,498,229	**14,703,216**	14,076,652
Overhead conductors and devices	13,683,961	3,757,254	**9,926,707**	9,423,950
Underground conduit	4,397,424	1,709,587	**2,687,837**	2,522,853
Underground conductors and devices	7,503,943	2,268,806	**5,235,137**	5,045,349
Transformers	13,441,003	7,244,337	**6,196,666**	5,629,568
Overhead and underground services	3,232,642	706,628	**2,526,014**	2,364,282
Meters	5,999,129	2,116,970	**3,882,159**	1,693,412
	85,812,625	28,144,459	**57,668,166**	53,479,100
General				
Land and easements	243,636	-	**243,636**	243,636
Buildings and fixtures	2,333,840	983,978	**1,349,862**	1,442,993
Vehicles	1,758,120	1,126,804	**631,316**	631,588
SCADA system	1,077,605	419,674	**657,931**	1,024,905
Computer equipment	1,080,096	615,096	**465,000**	254,911
Office furniture and equipment	215,341	147,285	**68,056**	74,990
Garage tools and equipment	673,744	343,130	**330,614**	120,209
Measurement and testing equipment	192,167	143,101	**49,066**	60,043
Communication equipment	115,039	76,662	**38,377**	47,835
Sentinel lights	18,942	1,894	**17,048**	-
Miscellaneous equipment	438,404	212,100	**226,304**	256,371
	8,146,934	4,069,724	**4,077,210**	4,157,481
	93,959,559	32,214,183	**61,745,376**	57,636,581
Contributions in aid of construction	(10,387,269)	(2,501,300)	**(7,885,969)**	(7,514,179)
	$ 83,572,290	$ 29,712,883	**$ 53,859,407**	$ 50,122,402

7. REGULATORY ASSETS AND LIABILITIES

	2012	2011
Regulatory assets		
Group 1 accounts		
RSVA - transmission network services	**$ -**	$ 366,010
RSVA - power (excluding global adjustment)	**129,235**	995,838
RSVA - global adjustment	**-**	266,932
Low voltage	**33,569**	-
Balances approved for disposition	**205,495**	-
Retail services & transaction requests variances	**-**	18,543
Total group 1 accounts	**368,299**	1,647,323
Group 2 accounts		
Smart meters and stranded meters	**722,536**	4,178,078
Special purpose charge	**12,595**	13,848
Other deferred charges	**146,254**	549,863
Total group 2 accounts	**881,385**	4,741,789
Total regulatory assets	**$ 1,249,684**	$ 6,389,112
Regulatory liabilities		
Group 1 accounts		
RSVA - transmission network services	**$ 241,061**	$ -
RSVA - global adjustment	**153,342**	-
RSVA - wholesale market services	**1,039,856**	990,874
RSVA - transmission connection services	**594,192**	1,061,385
Retail services & transaction requests variances	**4,008**	-
Low voltage	**-**	45,538
Balances approved for disposition	**-**	361,176
Total group 1 accounts	**2,032,459**	2,458,973
Group 2 accounts		
Smart meter funding	**-**	902,897
Future income taxes	**927,283**	897,781
Total group 2 accounts	**927,283**	1,800,678
Total regulatory liabilities	**$ 2,959,742**	$ 4,259,651

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7. REGULATORY ASSETS AND LIABILITIES *(continued)*

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 operation in the period that the assessment is made.

The regulatory assets and liabilities of the Corporation are as follows:

RSVA - transmission network services

This account is comprised of variances between the cost of the transmission network services provided by the Independent Electricity Systems Operator (IESO) and the amount charged by the Company to customers. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

RSVA - power (excluding global adjustment)

This account is comprised of variances between the cost of energy provided by IESO and the amount charged by the Company to customers. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

RSVA - global adjustment

This account is comprised of variances between the cost of the global adjustment charged by IESO and the amount charged by the Company to customers. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

Retail services & transaction request variances

This account is comprised of the variances between amounts charged by the Company to customers, based on regulated rates, and the corresponding cost for establishing, billing and maintaining service agreements. The account is subject to carrying charges in accordance with the OEB's direction.

Smart meters and stranded meters

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. The Company launched its smart meter project in 2008. As at December 31, 2012, all residential and small commercial customers have had smart meters installed. In 2008, the OEB ordered the Company to record all future expenditures and revenues related to smart meters to regulatory asset and liability accounts and allowed the Company to keep the net book value of the stranded meters related to the deployment of smart meters in its rate base. In 2012, the OEB approved for recovery the value of $857,731 for stranded conventional meters due to the smart meter conversion project.

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7. REGULATORY ASSETS AND LIABILITIES *(continued)*

Special purpose charge

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge (SPC) assessment under Section 26.1 of the Ontario Energy Board Act, 1998, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed the Company the amount of $147,781 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in the Ontario Regulation 66/10 (SPC Regulation). In accordance with Section 9 of the SPC Regulation, the Company was allowed to recover this amount.

Other deferred charges

This account is comprised primarily of the following amounts:

- OEB Cost Assessment - variances between OEB costs assessments invoiced to the Company for the OEB's 2004/05 and 2005/06 (up to April 30, 2006) fiscal years and OEB costs assessments previously included the Company's rates. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.
- Pension Contributions - pension costs associated with the cash contributions paid to Ontario Municipal Employees Retirement Savings (OMERS) for the period from January 1, 2005 to April 30, 2006. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.
- Green energy - the OEB has allowed distributors to begin recording expenditures for certain activities relating to the connection of renewable generation or the development of a smart grid.
- IFRS Transition Costs - one-time administrative incremental IFRS transition costs. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.

RSVA - wholesale market services

This account is comprised of variances between the cost of the operation of the IESO administered markets and the operation of the IESO-controlled grid and the amount charged by the Company to customers. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.

RSVA - transmission connection services

This account is comprised of variances between the cost of the transmission network services provided by IESO and the amount charged by the Company to customers. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

(continues)

7. REGULATORY ASSETS AND LIABILITIES *(continued)*

Low voltage

This account is comprised of variances between low voltage costs to the Company and the amount charged by the Company to the customers, these variances are not part of the electricity wholesale market. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

Balances approved for disposition

This account consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

Future income taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future income taxes.

8. CUSTOMER DEPOSITS

Customer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of contractual obligations. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability. Interest is accrued on customer deposit balances at rates established and reviewed by the Company on a quarterly basis. The current portion and long term portion of customer deposits are:

	2012	2011
Customer deposits	**$ 101,547**	$ 135,916
Current portion	**(50,000)**	(115,000)
Long term portion	**$ 51,547**	$ 20,916

9. LONG TERM DEBT

	2012	2011
Bank loans		
The original $2,000,000 ISDA swap for a 25-year term at 5.42% interest plus BA stamping fees at 0.75%. Payments are made on a quarterly basis and approximate $15,000 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due December 2029.	**$ 1,749,000**	$ 1,805,000

(continues)

9. LONG TERM DEBT *(continued)*

The original $10,700,000 ISDA swap for a 25-year term at 6.25% interest plus BA stamping fees at 0.75%. Payments are made on a quarterly basis and approximate $72,000 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2029.	**9,000,000**	9,266,000
The original $4,000,000 ISDA swap for a 15-year term at 5.27% interest plus BA stamping fees at 0.75%. Payments are made on a quarterly basis and approximate $68,500 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2020.	**2,310,000**	2,568,000
Debentures		
Infrastructure Ontario debenture bearing an interest rate of 5.01% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $70,587. The debenture is secured by certain distribution system assets and is due December 2032.	**1,770,428**	1,820,995
Infrastructure Ontario debenture bearing an interest rate of 4.73% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $192,154. The debenture is secured by certain distribution system assets and is due September 2035.	**5,352,536**	5,479,160
Infrastructure Ontario debenture bearing an interest rate of 3.72% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $144,801. The debenture is secured by certain distribution system assets and is due September 2020.	**1,988,040**	2,197,816
Infrastructure Ontario construction loan converted October 2012 to a debenture bearing an interest rate of 3.81% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $187,146. The debenture is secured by a third ranking General Security Agreement and is due December 2037.	**6,000,000**	6,000,000
Subtotal	**28,170,004**	29,136,971
Less: current portion	**(1,172,547)**	(966,967)
	$ 26,997,457	$ 28,170,004

The Company has entered into interest rate derivative agreements to manage the volatility of interest rates on long term debt. The Company converted the full face value of its variable rate term loans to a fixed rate of interest ranging from 5.27% to 6.25%. The related derivative agreements are in place until the maturity of the associated debt.

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9. LONG TERM DEBT *(continued)*

Future principal payments are approximately as follows:

2013	**$ 1,172,547**
2014	**1,231,421**
2015	**1,306,260**
2016	**1,376,106**
2017	**1,452,002**
Thereafter	**21,631,668**
	$ 28,170,004

The Company is subject to debt service coverage, debt to capitalization and current ratio covenants. At December 31, 2012, the Company is in compliance with these covenants.

The Company has access to an overdraft facility limit of $3,000,000. The terms of this facility is that it is on demand, bears interest at prime plus 0.5% and is secured by distribution assets. The overdraft facility balance was nil at the year end.

10. POST EMPLOYMENT BENEFITS

Post employment benefits other than pension provided by the Company include medical, dental and life insurance benefits. The Company actuarially determines the cost of other employment and post-employment benefits offered to employees using the projected benefit method prorated on service and based on management's best estimate assumptions. Under this method, the projected post-retirement benefit is deemed to be earned on a pro-rata basis over the years of service in the attribution period commencing at the date of hire, and ended at the earliest age the employee could retire and qualify for benefits. Compensated absences and termination benefits that do not vest or accumulate are recognized as an expense when the event occurs.

The Company measures its accrued benefits obligation for accounting purposes as at December 31 of each year. An actuarial valuation is completed every three years. The latest actuarial valuation was performed in February 2012 and no significant variance was found from the previous valuation.

11. SHARE CAPITAL

Authorized:
Unlimited Common shares

		2012	2011
Issued:			
1,000	Common shares	**$ 22,768,898**	$ 22,768,898

Share capital was issued as consideration for the net assets transferred from predecessor hydro-electric commissions as at January 1, 2001.

12. AMORTIZATION

	2012	2011
Total amortization	**$ 2,408,371**	$ 2,949,756
Less: amounts charged to other accounts	**(100,291)**	(324,247)
Amortization	**$ 2,308,080**	$ 2,625,509

13. INCOME TAXES

Reasons for the difference between tax expense for the year and the expected income taxes based on the statutory tax rate are as follows:

	2012	2011
Income before income taxes	**$ 2,016,414**	$ 2,586,693
Expected taxes based on a statutory rate of 26.50% (2011 - 28.25%)	**$ 534,350**	$ 730,741
Capital cost allowance in excess of amortization	**(229,736)**	(211,108)
Net change in regulatory assets and liabilities	**227,338**	(46,055)
Increase in post employment benefits reserve	**20,705**	2,905
SR&ED inclusion from prior years	**17,502**	(184,038)
Ontario small business deduction	**(35,000)**	(36,240)
Other additions and deductions	**8,841**	20,295
Income tax expense	**$ 544,000**	$ 276,500

14. FINANCIAL INSTRUMENTS

Fair value

Financial instruments of the Company include cash, accounts receivable, unbilled revenue, due from (to) associated companies, accounts payable, customer deposits and long term debt. All financial instruments except customer deposits and long term debt represent their fair value due to their short term nature. The carrying value of customer deposits and long term debt approximate their fair value as the interest rates are consistent with rates offered for similar items.

Exposure to interest rate risk, credit risk, foreign exchange risk and liquidity risk arises in the normal course of the Company's business. These risks are considered as follows:

Interest rate risk

The Company is exposed to interest rate risk in holding certain financial instruments. The Company's objective is to minimize net interest expense. The Company attempts to minimize interest rate risk by issuing long term fixed rate debt and ensuring that all payment obligations are met on an on-going basis.

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14. FINANCIAL INSTRUMENTS *(continued)*

Under the Company's bank agreements, the Company may obtain short term borrowing for working capital purposes. These borrowings expose the Company to fluctuations in short term interest rates (borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit). The fee payable for bankers' acceptances and letters of credit is based on a margin determined by reference to the Company's credit rating.

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, 2012, 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, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2012, there were no significant accounts receivable due from any single customer. The Company also collects security deposits from its customers as described in note 8.

At the year end, the Company's allowance for doubtful accounts was $100,000 (2011 - $130,000). The allowance is determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2012, approximately 5% (2011 - 7%) of the Company's accounts receivable was aged more than 60 days.

Foreign exchange risk

In the normal course of operation, the impact of foreign currency fluctuations is not material to the financial statements.

Liquidity risk

The Company monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Company has access to credit facilities and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

15. 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.

The Company considers its capital structure to consist of shareholder's equity, bank loans, debentures and Infrastructure Ontario financing. The Company's capital structure as at December 31, 2012 and December 31, 2011 was as follows:

	2012	2011
Bank loans	**$ 13,059,000**	$ 13,639,000
Debentures	**15,111,004**	15,497,971
Subtotal	**28,170,004**	29,136,971
Share capital	**22,768,898**	22,768,898
Retained earnings	**6,668,555**	6,396,141
Subtotal	**29,437,453**	29,165,039
	$ 57,607,457	$ 58,302,010

The Company's capital structure as at December 31, 2012, is 49% debt and 51% equity (2011 - 50% debt and 50% equity). There have been no changes in the Company's approach to capital management during the year.

16. PRUDENTIAL SUPPORT

Norfolk Power Distribution Inc. is required through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Norfolk Power Distribution Inc. fails to make payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2012 the Company provided prudential support in the form of bank letters of credit of $1,424,163.

17. SUBSEQUENT EVENTS

In October 2012, the Company's shareholder, Norfolk County unanimously agreed to sell Norfolk Power Inc. and its subsidiaries. In this regard, on April 2, 2013 an agreement has been signed with a purchaser for the sale of the shares of Norfolk Power Inc. which includes Norfolk Power Distribution Inc. and Norfolk Energy Inc.. The sale is subject to OEB approval, and is expected to be completed within the 2013 fiscal year.

18. COMPARATIVE FIGURES

Some of the comparative figures have been reclassified to conform to the current year's presentation.

Norfolk Power Distribution Inc.

Financial Statements

December 31, 2011

Norfolk Power Distribution Inc.

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Norfolk Power Distribution Inc.

We have audited the accompanying financial statements of Norfolk Power Distribution Inc., which comprise the balance sheet as at December 31, 2011 and the statements of operations, retained earnings and cash flow for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Norfolk Power Distribution Inc. as at December 31, 2011, and the results of its operations and its cash flow for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse + Rosebrugh LLP

April 18, 2012
Simcoe, Ontario

Chartered Accountants
Licensed Public Accountants

Management's Responsibility for Financial Reporting

The financial statements of Norfolk Power Distribution Inc. have been prepared in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. These statements include certain amounts based on management's estimates and judgments. Management has determined such amounts based on a reasonable basis in order to ensure that the financial statements are presented fairly in all material respects.

The integrity and reliability of Norfolk Power Distribution Inc.'s reporting systems are achieved through the use of formal policies and procedures, the careful selection of employees and an appropriate division of responsibilities. These systems are designed to provide reasonable assurance that the financial information is reliable and accurate.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit and Finance Committee. The Committee is appointed by the Board and meets periodically with management and the shareholder's auditors to review significant accounting, reporting and internal control matters. Following its review of the financial statements and discussions with the auditors, the Audit and Finance Committee reports to the Board of Directors prior to its approval of the financial statements. The Committee also considers, for review by the Board and approval by the shareholder, the engagement or re-appointment of the external auditors.

The financial statements have been audited on behalf of the shareholder by Millard, Rouse & Rosebrugh LLP , in accordance with generally accepted auditing standards.

Brad Randall, President & CEO

Jody McEachran, Chief Financial Officer

J.J. Knott, Board of Directors Chair

Frank Casey, Audit and Finance Committee Chair

Norfolk Power Distribution Inc.

Balance Sheet

As at December 31, 2011

	2011	2010
ASSETS		
Current		
Cash	$ 3,142,592	$ 836,521
Accounts receivable	4,253,675	4,191,422
Unbilled revenue	3,953,201	4,526,049
Due from associated companies *(Note 5)*	-	82,481
Income taxes recoverable	729,939	375,027
Inventory	533,619	549,678
Prepaid expenses	395,003	319,822
	13,008,029	10,881,000
Property and equipment *(Note 6)*	50,122,402	49,389,910
Regulatory assets *(Note 7)*	6,389,112	5,302,520
Future income taxes	897,781	1,215,250
	$ 70,417,324	$ 66,788,680
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable	$ 6,707,499	$ 6,289,294
Due to associated companies *(Note 5)*	134,166	-
Current portion of customer deposits *(Note 8)*	115,000	130,000
Demand loans *(Note 9)*	-	3,500,000
Current portion of long term debt *(Note 10)*	966,967	918,000
	7,923,632	10,837,294
Regulatory liabilities *(Note 7)*	4,259,651	4,181,256
Customer deposits *(Note 8)*	20,916	110,363
Long term debt *(Note 10)*	28,170,004	23,137,121
Post employment benefits *(Note 11)*	878,082	867,800
	41,252,285	39,133,834
Shareholder's equity		
Share capital *(Note 12)*	22,768,898	22,768,898
Retained earnings	6,396,141	4,885,948
	29,165,039	27,654,846
	$ 70,417,324	$ 66,788,680

See accompanying notes

Norfolk Power Distribution Inc.

Statement of Retained Earnings

Year ended December 31, 2011

	2011	2010
Retained earnings - beginning of year	**$ 4,885,948**	$ 3,721,271
Net income for the year	**2,310,193**	1,999,888
	7,196,141	5,721,159
Dividends	**(800,000)**	(835,211)
RETAINED EARNINGS - END OF YEAR	**$ 6,396,141**	$ 4,885,948

See accompanying notes

Norfolk Power Distribution Inc.

Statement of Operations

Year ended December 31, 2011

	2011	2010
REVENUE		
Energy sales	**$ 32,764,997**	$ 31,033,780
Distribution services	**11,072,876**	10,802,100
Other	**616,371**	454,744
	44,454,244	42,290,624
Cost of power	**32,764,997**	31,033,780
Distribution revenue	**11,689,247**	11,256,844
EXPENSES		
Distribution system - operation and maintenance	**2,191,894**	2,222,251
Billing and collecting	**1,008,136**	971,841
Community relations	**48,570**	48,761
Administrative and general expense	**1,553,796**	1,682,502
Taxes other than amounts in lieu of corporate taxes	**36,435**	68,210
	4,838,831	4,993,565
Income before amortization, interest and income taxes	**6,850,416**	6,263,279
Amortization *(Note 13)*	**2,625,509**	2,351,567
Interest	**1,638,214**	1,380,824
	4,263,723	3,732,391
Income before income taxes	**2,586,693**	2,530,888
Income taxes *(Note 14)*	**276,500**	531,000
NET INCOME FOR THE YEAR	**$ 2,310,193**	$ 1,999,888

See accompanying notes

Norfolk Power Distribution Inc.
Statement of Cash Flow
Year ended December 31, 2011

	2011	2010
OPERATING ACTIVITIES		
Net income for the year	**$ 2,310,193**	$ 1,999,888
Items not affecting cash:		
Amortization *(Note 13)*	**2,949,756**	2,702,287
Future income taxes	**317,469**	403,338
Post employment benefits	**10,282**	62,463
Loss (gain) on disposal of property and equipment	**(13,890)**	3,138
	5,573,810	5,171,114
Changes in non-cash working capital:		
Accounts receivable	**(62,253)**	475,275
Unbilled revenue	**572,848**	118,509
Amount due from (to) associated companies	**216,647**	(64,623)
Income taxes recoverable	**(354,912)**	(608,815)
Inventory	**16,059**	22,795
Prepaid expenses	**(75,181)**	(63,841)
Accounts payable	**418,205**	(1,242,123)
	731,413	(1,362,823)
Cash flow from operating activities	**6,305,223**	3,808,291
INVESTING ACTIVITIES		
Purchase of property and equipment	**(5,053,411)**	(4,253,107)
Proceeds on disposal of property and equipment	**46,800**	36,500
Contributions in aid of construction	**1,338,253**	819,501
Net change in regulatory assets and liabilities	**(1,008,197)**	(1,110,982)
Cash flow used by investing activities	**(4,676,555)**	(4,508,088)
FINANCING ACTIVITIES		
Repayment of customer deposits	**(104,447)**	(16,067)
Demand loan financing (repaid)	**(3,500,000)**	1,500,000
Loans and debentures financing received	**6,000,000**	1,200,020
Repayment of loans and debentures	**(918,150)**	(559,803)
Dividends declared	**(800,000)**	(835,211)
Repayment of capital lease obligations	**-**	(40,864)
Cash flow from financing activities	**677,403**	1,248,075
INCREASE IN CASH	**2,306,071**	548,278
Cash - beginning of year	**836,521**	288,243
CASH - END OF YEAR	**$ 3,142,592**	$ 836,521

See accompanying notes

1. NATURE OF ACTIVITIES

On November 1, 2000, Norfolk Power Inc. was incorporated under the Ontario Business Corporations Act, along with its two wholly owned subsidiary companies, Norfolk Power Distribution Inc. and Norfolk Energy Inc. Norfolk Power Distribution Inc. provides regulated electricity distribution services. Norfolk Energy Inc. provides home comfort rentals, conservation innovation, high-speed telecommunication fibre optics and other energy services.

As the sole shareholder of Norfolk Power Distribution Inc.'s parent company (Norfolk Power Inc.), Norfolk County is considered a related party. All transactions with Norfolk County are conducted within the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

Norfolk Power Distribution Inc. is a rate-regulated enterprise and Norfolk Energy Inc. is a non-rate-regulated enterprise. The difference is rate-regulated enterprises have policies that have accounting treatments differing from Canadian generally accepted accounting principles (GAAP) for enterprises operating in a non-rate-regulated environment, this is discussed in further detail in note 3.

Norfolk Power Inc. consolidated financial statements have also been prepared separately that include the accounts of Norfolk Power Inc., Norfolk Power Distribution Inc. and Norfolk Energy Inc.

2. REGULATION

In April 1999, the government of Ontario began restructuring Ontario's electricity industry. Under regulations passed pursuant to the restructuring, the Company and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator (IESO) and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board (OEB).

The OEB has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified account records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, and ensuring that electricity distribution companies fulfills their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future.

(continues)

2. REGULATION *(continued)*

The Company is required to charge its customers for the following amounts (all of which, other than distribution charges, represent a pass through of amounts payable to third parties):

1. *Distribution Charges.* Distribution charges are designed to recover the costs incurred by the Company in delivering electricity to customers and the OEB-allowed rate of return. Distribution charges are regulated by the OEB and typically comprise of a fixed charge and a usage-based (consumption) charge.

   The volume of electricity consumed by the Company's customers during any period is governed by events largely outside the Company's control, principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity.

2. *Electricity Price and Related Regulated Adjustments.* The electricity price and related regulated adjustments represent a pass through of the commodity cost of electricity.

3. *Retail Transmission Rate.* The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

4. *Wholesale Market Service Charge.* The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

The Company's electricity distribution rates are typically effective from May 1 to April 30 of the following year. Accordingly, for the first four months of 2011, distribution revenue was based on the rates approved in 2010. Distribution revenue for the period from May 1, 2011 to December 31, 2011 was based on the distribution rates approved in 2011.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements of Norfolk Power Distribution Inc. have been prepared in accordance with Canadian GAAP, including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" (AP Handbook) and reflect the significant accounting policies summarized below:

Regulation

The following three regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

The OEB has the general authority to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in the timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable in the future from 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 recovered for specific expenditures in excess of costs incurred by the Company. These liabilities are expected to be settled with future rate adjustments. Specific regulatory assets and liabilities are disclosed in note 7.

Contributions in aid of construction

Capital contributions received from outside sources are used to finance additions to property and equipment of the Company. According to the AP Handbook, capital contributions received are treated as a reduction to property and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a reduction to amortization expense at an equivalent rate to that used for the amortization of the related property and equipment.

Future income taxes

Income taxes are reported using the tax liability method, as follows: current income tax expense is the estimated income taxes payable for the current year after any refunds or the use of losses incurred in previous years, and future income taxes reflect:

- the temporary differences between the carrying amounts of assets and liabilities for accounting purposes and the amounts used for tax purposes;
- the benefit of unutilized tax losses that will more likely than not be realized and carried forward to future years to reduce income taxes.

Future income taxes are estimated using the rates enacted by tax law and those substantively enacted for the years in which future income taxes assets are likely to be realized, or future income tax liabilities settled. The effect of a change in tax rates on future income tax assets and liabilities is included in deferred costs or recoveries of regulatory assets and liabilities in the period when the change is substantively enacted.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Revenue recognition

Energy sales and distribution services revenues are based on OEB approved rates and are recognized on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. Other revenues related to sales of other services are recognized as the services are rendered.

Inventory

Inventory consists of repair parts, supplies and materials held for operating and maintenance activities and are valued at lower of cost and net realizable value. Cost is determined using the weighted average method.

Property and equipment

Property and equipment are valued at acquisition cost and include contracted services, materials, labour, engineering costs, interest and overheads. Gains or losses at retirement or disposition are credited or charged to other income in the year of disposal.

Amortization is provided on a straight line basis for property and equipment available for use over their estimated economic lives, at the following annual rates:

Buildings and fixtures	50 years
Transformer station equipment	40 years
Distribution station equipment	30 years
Distribution system	25 years
Meters	25 years
Vehicles	4 to 10 years
SCADA system	15 years
Computer equipment	5 years
Office furniture and equipment	10 years
Garage tools and equipment	10 years
Measurement and testing equipment	10 years
Communication equipment	10 years
Miscellaneous equipment	10 years

The Company reviews property and equipment for impairment whenever events or circumstances indicate that the carrying amount is not recoverable. Any resulting impairment loss is recorded in the period in which the impairment occurs.

Payments in lieu of income taxes

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing taxable 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.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Pension

Employees of the Company are members of the Ontario Municipal Employees Retirement System (OMERS) which is a multi-employer public sector contributory defined benefit pension plan. The pension fund is financed by equal contributions from participating employers and employees and by the investment earnings of the fund. Contributions made by the Company on behalf of the employees amounted to approximately $260,000 (2010 - $240,000).

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. Significant areas requiring the use of management estimates relate to regulatory assets and liabilities, employee future benefits and amortization. Actual results could differ from amounts recorded in these financial statements, including changes as a result of future decisions made by the OEB or the Minister of Energy.

Interest rate swaps

The Company is party to interest rate swap agreements used to manage the exposure to market risks from changing interest rates. The Company's policy is not to utilize derivative financial instruments for trading or speculative purposes.

The Company has not hedged these agreements and the change in fair value of the swaps is reflected in the Statement of Operations. The amount recorded on the Statement of Financial Position is recorded at fair value.

Financial instruments

At inception, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Gains and losses related to the measurement of financial instruments are reported in the statement of operations. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Company. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties. Further discussion of financial instruments for the Company is included in note 15 of the financial statements.

4. INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2008, the Accounting Standards Board (AcSB) confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards (IFRS) by January 1, 2011. Also, 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.

In 2010, the AcSB granted an optional one year deferral for IFRS adoption for entities subject to rate regulation. This decision came in light of the uncertainty created by the International Accounting Standards Board (IASB) in regard to the rate-regulated project which is assessing the potential recognition of regulatory assets and regulatory liabilities under IFRS. 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.

Given the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting (RRA) standard under IFRS and the potential material impact of RRA on the Company's financial statements, the Company has decided to elect the optional one year deferral of its adoption of IFRS.

As a result of these developments related to RRA under IFRS and the uncertainty regarding the impact of IFRS on the OEB electricity distribution rates application process, the Company cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and results of operation. The Company will continue to assess and evaluate the impact of this adoption.

5. DUE FROM (TO) ASSOCIATED COMPANIES

The Company is wholly owned by Norfolk Power Inc. Norfolk Power Inc. also wholly owns Norfolk Energy Inc. Transactions with these associated companies are conducted within the normal course of operations and consideration paid is on similar terms as transactions with unrelated parties.

Balances owing at December 31 have no set repayment terms:

	2011	2010
Amounts owing to Norfolk Power Inc.	**$ (206,881)**	$ (62,851)
Amounts due from Norfolk Energy Inc.	**72,715**	145,332
	$ (134,166)	$ 82,481

6. PROPERTY AND EQUIPMENT

	Cost	Accumulated amortization	**2011**	2010
Distribution				
Land, land rights and easements	$ 694,044	$ -	**$ 694,044**	$ 694,044
Transformer station building	1,620,078	212,977	**1,407,101**	1,439,503
Transformer station equipment	8,912,383	747,233	**8,165,150**	8,387,996
Distribution station equipment	2,910,312	453,573	**2,456,739**	2,404,514
Poles, towers and fixtures	22,166,306	8,089,654	**14,076,652**	13,659,081
Overhead conductors and devices	12,973,773	3,549,823	**9,423,950**	8,660,771
Underground conduit	4,170,822	1,647,969	**2,522,853**	2,503,559
Underground conductors and devices	7,083,825	2,038,476	**5,045,349**	4,923,361
Transformers	12,688,457	7,058,889	**5,629,568**	5,271,878
Overhead and underground services	3,000,229	635,947	**2,364,282**	2,258,010
Meters	4,228,306	2,534,894	**1,693,412**	1,781,996
	80,448,535	26,969,435	**53,479,100**	51,984,713
General				
Land and easements	243,636	-	**243,636**	243,636
Buildings and fixtures	2,322,460	879,467	**1,442,993**	1,468,859
Vehicles	1,729,799	1,098,211	**631,588**	476,108
SCADA system	1,447,671	422,766	**1,024,905**	844,440
Computer equipment	574,583	319,672	**254,911**	281,928
Office furniture and equipment	204,678	129,688	**74,990**	76,871
Garage tools and equipment	327,257	207,048	**120,209**	133,419
Measurement and testing equipment	188,843	128,800	**60,043**	70,554
Communication equipment	115,039	67,204	**47,835**	51,872
Miscellaneous equipment	428,221	171,850	**256,371**	299,192
	7,582,187	3,424,706	**4,157,481**	3,946,879
	88,030,722	30,394,141	**57,636,581**	55,931,592
Contributions in aid of construction	(9,811,775)	(2,297,596)	**(7,514,179)**	(6,541,682)
	$ 78,218,947	$ 28,096,545	**$ 50,122,402**	$ 49,389,910

7. REGULATORY ASSETS AND LIABILITIES

		2011		2010
Regulatory assets				
Group 1 accounts				
RSVA - transmission network services	**$**	**366,010**	$	485,439
RSVA - power (excluding global adjustment)		**995,838**		200,034
RSVA - global adjustment		**266,932**		647,602
Retail services & transaction requests variances		**18,543**		17,997
Total group 1 accounts		**1,647,323**		1,351,072
Group 2 accounts				
Smart meters		**4,178,078**		3,547,622
Special purpose charge		**13,848**		58,780
Other deferred charges		**549,863**		345,046
Total group 2 accounts		**4,741,789**		3,951,448
Total regulatory assets	**$**	**6,389,112**	$	5,302,520
Regulatory liabilities				
Group 1 accounts				
RSVA - wholesale market services	**$**	**990,874**	$	474,686
RSVA - transmission connection services		**1,061,385**		613,141
Low voltage		**45,538**		68,300
Balances approved for disposition		**361,176**		1,134,968
Total group 1 accounts		**2,458,973**		2,291,095
Group 2 accounts				
Smart meter funding		**902,897**		674,911
Future income taxes		**897,781**		1,215,250
Total group 2 accounts		**1,800,678**		1,890,161
Total regulatory liabilities	**$**	**4,259,651**	$	4,181,256

(continues)

7. REGULATORY ASSETS AND LIABILITIES *(continued)*

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 operation in the period that the assessment is made.

The regulatory assets and liabilities of the Corporation are as follows:

RSVA - transmission network services

This account is comprised of variances between the cost of the transmission network services provided by the Independent Electricity Systems Operator (IESO) and the amount charged by the Company to customers. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

RSVA - power (excluding global adjustment)

This account is comprised of variances between the cost of energy provided by IESO and the amount charged by the Company to customers. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

RSVA - global adjustment

This account is comprised of variances between the cost of the global adjustment charged by IESO and the amount charged by the Company to customers. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

Retail services & transaction request variances

This account is comprised of the variances between amounts charged by the Company to customers, based on regulated rates, and the corresponding cost for establishing, billing and maintaining service agreements. The account is subject to carrying charges in accordance with the OEB's direction.

Smart meters

The smart meters regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario. The Company launched its smart meter project in 2008. As at December 31, 2011, all residential and small commercial customers have had smart meters installed. In 2008, the OEB ordered the Company to record all future expenditures and revenues related to smart meters to regulatory asset and liability accounts and allowed the Company to keep the net book value of the stranded meters related to the deployment of smart meters in its rate base.

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7. REGULATORY ASSETS AND LIABILITIES *(continued)*

Special purpose charge

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge (SPC) assessment under Section 26.1 of the Ontario Energy Board Act, 1998, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB assessed the Company the amount of $147,781 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in the Ontario Regulation 66/10 (SPC Regulation). In accordance with Section 9 of the SPC Regulation, the Company was allowed to recover this amount.

Other deferred charges

This account is comprised primarily of the following amounts:

- OEB Cost Assessment - variances between OEB costs assessments invoiced to the Company for the OEB's 2004/05 and 2005/06 (up to April 30, 2006) fiscal years and OEB costs assessments previously included the Company's rates. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.
- Pension Contributions - pension costs associated with the cash contributions paid to Ontario Municipal Employees Retirement Savings (OMERS) for the period from January 1, 2005 to April 30, 2006. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.
- Green energy - the OEB has allowed distributors to begin recording expenditures for certain activities relating to the connection of renewable generation or the development of a smart grid.
- IFRS Transition Costs - one-time administrative incremental IFRS transition costs. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.

RSVA - wholesale market services

This account is comprised of variances between the cost of the operation of the IESO administered markets and the operation of the IESO-controlled grid and the amount charged by the Company to customers. The balance is subject to carrying charges following the OEB prescribed methodology and related rates.

RSVA - transmission connection services

This account is comprised of variances between the cost of the transmission network services provided by IESO and the amount charged by the Company to customers. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

(continues)

7. REGULATORY ASSETS AND LIABILITIES *(continued)*

Low voltage

This account is comprised of variances between low voltage costs to the Company and the amount charged by the Company to the customers, these variances are not part of the electricity wholesale market. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

Balances approved for disposition

This account consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The account is subject to carrying charges following the OEB prescribed methodology and related rates.

Future income taxes

This regulatory liability account relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future income taxes.

8. CUSTOMER DEPOSITS

Customer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of contractual obligations. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability. Interest is accrued on customer deposit balances at rates established and reviewed by the Company on a quarterly basis. The current portion and long term portion of customer deposits are:

	2011	2010
Customer deposits	**$ 135,916**	$ 240,363
Current portion	**(115,000)**	(130,000)
Long term portion	**$ 20,916**	$ 110,363

9. DEMAND LOANS

	2011	2010
Demand loan was fully paid in 2011.	**$ -**	$ 3,000,000
Demand loan was fully paid in 2011.	**-**	500,000
	$ -	$ 3,500,000

The Company also has access to an overdraft facility limit of $3,000,000. The terms of this facility is that it is on demand, bears interest at prime plus 0.5% and is secured by distribution assets. The overdraft facility balance was nil at the year end.

10. LONG TERM DEBT

	2011	2010
Bank loans		
The original $2,000,000 ISDA swap for a 25-year term at 5.42% interest plus BA stamping fees at 2%. Principal and interest payments are made on a quarterly basis and approximate $13,500 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due December 2029.	**$ 1,805,000**	$ 1,859,000
The original $10,700,000 ISDA swap for a 25-year term at 6.25% interest plus BA stamping fees at 0.75%. Principal and interest payments are made on a quarterly basis and approximate $63,750 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2029.	**9,266,000**	9,516,000
The original $4,000,000 ISDA swap for a 15-year term at 5.27% interest plus BA stamping fees at 2%. Principal and interest payments are made on a quarterly basis and approximate $61,500 plus interest. The loan is secured by certain distribution assets as per the General Security Agreement and is due September 2020.	**2,568,000**	2,811,000
Debentures		
Infrastructure Ontario debenture bearing an interest rate of 5.01% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $70,587. The debenture is secured by certain distribution system assets and is due December 2032.	**1,820,995**	1,869,121
Infrastructure Ontario debenture bearing an interest rate of 4.73% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $192,154. The debenture is secured by certain distribution system assets and is due September 2035.	**5,479,160**	5,600,000
Infrastructure Ontario debenture bearing an interest rate of 3.72% per annum over the term of the debenture. The amount is repayable in semi-annual blended principal and interest payments of $144,801. The debenture is secured by certain distribution system assets and is due September 2020.	**2,197,816**	2,400,000

(continues)

10. LONG TERM DEBT *(continued)*

Infrastructure Ontario construction loan to be converted October 2012 to a debenture bearing an interest rate of 4.86% per annum over the term of the debenture. The amount repayable in monthly blended principal and interest payments of $34,588. The debenture is secured by a third ranking General Security Agreement and is due October 2037.	**6,000,000**	-
Subtotal	**29,136,971**	24,055,121
Less: current portion	**(966,967)**	(918,000)
	$ 28,170,004	$ 23,137,121

The Company has entered into interest rate derivative agreements to manage the volatility of interest rates on long term debt. The Company converted the full face value of its variable rate term loans to a fixed rate of interest ranging from 5.27% to 6.25%. The related derivative agreements are in place until the maturity of the associated debt.

Future principal payments are approximately as follows:

2012	**$ 966,967**
2013	**1,440,523**
2014	**1,493,740**
2015	**1,562,704**
2016	**1,626,450**
Thereafter	**22,046,587**
	$ 29,136,971

The Company is subject to debt service coverage, debt to capitalization and current ratio covenants. At December 31, 2011, the Company is in compliance with these covenants.

11. POST EMPLOYMENT BENEFITS

Post employment benefits other than pension provided by the Company include medical, dental and life insurance benefits. The Company actuarially determines the cost of other employment and post-employment benefits offered to employees using the projected benefit method prorated on service and based on management's best estimate assumptions. Under this method, the projected post-retirement benefit is deemed to be earned on a pro-rata basis over the years of service in the attribution period commencing at the date of hire, and ended at the earliest age the employee could retire and qualify for benefits. Compensated absences and termination benefits that do not vest or accumulate are recognized as an expense when the event occurs.

The Company measures its accrued benefits obligation for accounting purposes as at December 31 of each year. An actuarial valuation is completed every three years. The latest actuarial valuation was performed in February 2012 and no significant variance was found from the previous valuation.

12. SHARE CAPITAL

Authorized:
Unlimited Common shares

		2011	2010
Issued:			
1,000	Common shares	**$ 22,768,898**	$ 22,768,898

Share capital was issued as consideration for the net assets transferred from predecessor hydro-electric commissions as at January 1, 2001.

13. AMORTIZATION

	2011	2010
Total amortization	**$ 2,949,756**	$ 2,702,287
Less: amounts charged to other accounts	**(324,247)**	(350,720)
Amortization	**$ 2,625,509**	$ 2,351,567

14. INCOME TAXES - CURRENT

Reasons for the difference between tax expense for the year and the expected income taxes based on the statutory tax rate are as follows:

	2011	2010
Income before income taxes	**$ 2,586,693**	$ 2,530,888
Expected taxes based on a statutory rate of 28.25% (2010 - 31.00%)	**$ 730,741**	$ 784,575
Capital cost allowance in excess of amortization	**(211,108)**	(223,683)
Net change in regulatory assets and liabilities	**(46,055)**	(36,037)
Increase in post employment benefits reserve	**2,905**	19,364
SR&ED inclusion from prior years	**(184,038)**	-
Ontario small business deduction	**(36,240)**	(3,614)
Other additions and deductions	**20,295**	(9,605)
Current tax expense	**$ 276,500**	$ 531,000

15. FINANCIAL INSTRUMENTS

Fair value

Financial instruments of the Company include cash, accounts receivable, unbilled revenue, due from (to) associated companies, accounts payable, customer deposits and long term debt. All financial instruments except customer deposits and long term debt represent their fair value due to their short term nature. The carrying value of customer deposits and long term debt approximate their fair value as the interest rates are consistent with rates offered for similar items.

Exposure to interest rate risk, credit risk, foreign exchange risk and liquidity risk arises in the normal course of the Company's business. These risks are considered as follows:

Interest rate risk

The Company is exposed to interest rate risk in holding certain financial instruments. The Company's objective is to minimize net interest expense. The Company attempts to minimize interest rate risk by issuing long term fixed rate debt and ensuring that all payment obligations are met on an on-going basis.

Under the Company's bank agreements, the Company may obtain short term borrowing for working capital purposes. These borrowings expose the Company to fluctuations in short term interest rates (borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit). The fee payable for bankers' acceptances and letters of credit is based on a margin determined by reference to the Company's credit rating.

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, 2011, 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, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2011, there were no significant accounts receivable due from any single customer. The Company also collects security deposits from its customers as described in note 8.

At the year end, the Company's allowance for doubtful accounts was $130,000 (2010 - $130,000). The allowance is determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2011, approximately 7% (2010 - 5%) of the Company's accounts receivable was aged more than 60 days.

Foreign exchange risk

In the normal course of operation, the impact of foreign currency fluctuations is not material to the financial statements.

Liquidity risk

The Company monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The Company has access to credit facilities and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

16. 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.

The Company considers its capital structure to consist of shareholder's equity, bank loans, debentures and Infrastructure Ontario financing. The Company's capital structure as at December 31, 2011 and December 31, 2010 was as follows:

	2011	2010
Bank loans	**$ 13,639,000**	$ 14,186,000
Debentures	**15,497,971**	9,869,121
Subtotal	**29,136,971**	24,055,121
Share capital	**22,768,998**	22,768,898
Retained earnings	**6,403,141**	4,885,948
Subtotal	**29,172,139**	27,654,846
	$ 58,309,110	$ 51,709,967

The Company's capital structure as at December 31, 2011, is 50% debt and 50% equity (2010 - 47% debt and 53% equity). There have been no changes in the Company's approach to capital management during the year.

17. PRUDENTIAL SUPPORT

Norfolk Power Distribution Inc. is required through the IESO, to provide security to mitigate the Company's risk of default based on its expected activity in the electricity market. The IESO could draw on this guarantee if Norfolk Power Distribution Inc. fails to make payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2011 the Company provided prudential support in the form of bank letters of credit of $1,424,163.

18. COMPARATIVE FIGURES

Some of the comparative figures have been reclassified to conform to the current year's presentation.

THE CORPORATION OF NORFOLK COUNTY

RESOLUTION # 3.

DATE: April 2, 2013

COUNCIL

MOVED BY **Councillor** Luke

SECONDED BY **Councillor** Oliver

WHEREAS The Corporation of Norfolk County (the "Corporation") is the sole shareholder of Norfolk Power Inc. ("NPI");

AND WHEREAS The Corporation desires to approve the sale of all of the issued and outstanding shares of NPI (the "Shares") to Hydro One Inc. (the "Transaction"), substantially on the terms and conditions of the purchase agreement between the Corporation and Hydro One Inc. attached hereto as Schedule "Schedule A" (the "Share Purchase Agreement");

AND WHEREAS the Transaction is subject to approval by the Ontario Energy Board pursuant to section 86 of the *Ontario Energy Board Act, 1998* and the Ontario Energy Board's Preliminary Filing Requirements for Mergers, Acquisitions, Amalgamations and Divestitures in the Ontario Electricity Transmission and Distribution Sector ("MAADs Application").

RESOLVED THAT:

1. The Corporation is authorized to sell the Shares for the consideration and substantially on the terms and conditions of the Share Purchase Agreement;
2. The Corporation authorizes the County Solicitor to prepare and submit the MAADs Application to the Ontario Energy Board;

3. The Share Purchase Agreement is approved as containing a correct statement of the terms and conditions on which the sale of the Shares are to be made and of the respective rights and obligations of the Corporation and Hydro One under the Share Purchase Agreement and the Mayor is authorized to execute and deliver the Share Purchase Agreement and MAADs Application on behalf of the Corporation, and any additions and amendments to the Share Purchase Agreement as the County Solicitor may approve and deem necessary, the execution and delivery of the Share Purchase Agreement and MAADs Application by the Mayor being conclusive evidence of such approval; and

4. The Mayor, Clerk or Deputy Clerk are authorized and directed to take all such action as may be necessary or advisable to complete the Transaction and/or MAADs Application including, but not limited to, the execution and delivery of such ancillary agreements, documents, letters, certificates, writings and receipts as in the opinion of the County Solicitor may be necessary or desirable to complete the Transaction and/or MAADs Application.

Carried:

BY-LAW NO. 2013-64

OF

The Corporation of Norfolk County

BEING A BY-LAW TO AUTHORIZE THE EXECUTION OF A SHARE PURCHASE AGREEMENT WITH HYDRO ONE INC.

WHEREAS Sections 5 and 9 of the Municipal Act, 2001, S.O. 2001, c. 25, as amended, provide that the powers of the Municipal Council shall be exercised by by-law, unless the municipality is specifically authorized to do otherwise and that the municipality has the capacity, rights, powers and privileges of a natural person for the purposes of exercising its authority;

AND WHEREAS, The Corporation of Norfolk County being the Shareholder of Norfolk Power Inc. is desirous to approve the sale of all of the issued and outstanding shares of Norfolk Power Inc. to Hydro One Inc. (the "Transaction") and to authorize the entering into, execution, and delivery of the Share Purchase Agreement with Hydro One Inc;

AND WHEREAS, the Transaction is subject to approval by the Ontario Energy Board pursuant to section 86 of the *Ontario Energy Board Act, 1998* and the Ontario Energy Board's Preliminary Filing Requirements for Mergers, Acquisitions, Amalgamations and Divestitures in the Ontario Electricity Transmission and Distribution Sector ("MAADs Application");

NOW THEREFORE THE COUNCIL OF THE CORPORATION OF NORFOLK COUNTY HEREBY ENACTS AS FOLLOWS:

1. That Council does hereby confirm and ratify the Share Purchase Agreement with Hydro One Inc. hereto annexed and marked as Schedule "A" to this By-Law;

2. That Council does hereby authorize, confirm and approve the County Solicitor to prepare and submit the MAADs Application to the Ontario Energy Board;

3. That the Mayor being the Designated Representative of the Shareholder under the Shareholder Direction, is hereby authorized to execute on behalf of the Corporation the Share Purchase Agreement hereto annexed and marked as Schedule "A" to this By-Law, any agreements amending the Share Purchase Agreement, the MAADs Application, and all other documentation necessary, in the opinion of the County Solicitor, to complete the Transaction;

4. That the Mayor, Clerk, or Deputy Clerk are hereby authorized and directed to take all such action under the Share Purchaser Agreement and/or MAADs Application necessary or advisable to complete the Transaction including, but not limited to, the execution and delivery of the such ancillary agreements, documents, letters, certificates, writings and receipts as in the opinion of the County Solicitor may be necessary or desirable to complete the Transaction; and

5. That the effective date of this By-Law shall be the date of final passage thereof.

ENACTED AND PASSED THIS 2ND DAY OF APRIL, 2013.

First Reading:	April 2, 2013	Mayor
Second Reading:	April 2, 2013	
Third Reading:	April 2, 2013	Clerk/Manager of Council Services

Attachment 14

Bill Impact Calculations

	Residential					
	Volume	**Current Rates**	**Current Charges ($)**	**Rates as per Acquisition Agreement**	**Charges as per Acquisition Agreement ($)**	**% Change**
Monthly Consumption (kWh)	**800**					
Total Loss Factors	**1.0564**					
TOU - Off Peak Consumption	541	0.067	36.24	0.067	36.24	
TOU - Mid Peak Consumption	152	0.104	15.82	0.104	15.82	
TOU - On Peak Consumption	152	0.124	18.86	0.124	18.86	
Total: Commodity			**70.92**		**70.92**	**0.00%**
DX Fixed Charge ($)	1	20.87	20.87	20.56	20.56	
DX Fixed Charge Rate Riders ($)	1	1.82	1.82	1.82	1.82	
DX Vol. Charge ($/kWh)	800	0.0218	17.44	0.0215	17.20	
DX Vol. Rate Riders ($/kWh)	800	-0.0002	-0.16	-0.0002	-0.16	
Low Voltage Vol. Charge ($/kWh)	800	0.0009	0.72	0.0009	0.72	
Low Voltage Vol. Rate Riders ($/kWh)	800	0.0000	0.00	0.0000	0.00	
Distribution Base Rates Only			**39.03**		**38.48**	**-1.41%**
Total: Distribution			**40.69**		**40.14**	**-1.35%**
TX-Network ($/kWh)	845	0.0067	5.66	0.0067	5.66	
TX-Connection ($/kWh)	845	0.0032	2.70	0.0032	2.70	
Total: Transmission			**8.37**		**8.37**	**0.00%**
WMSC ($/kWh)	845	0.0044	3.72	0.0044	3.72	
RRRP ($/kWh)	845	0.0012	1.01	0.0012	1.01	
DRC ($/kWh)	800	0.007	5.60	0.007	5.60	
SSA ($)	1	0.25	0.25	0.25	0.25	
Total: Regulatory			**10.58**		**10.58**	**0.00%**
Total Bill (Before Taxes)			$130.56		$130.01	
HST		13%	$16.97	13%	$16.90	
Total Bill (Including HST)			$147.53		$146.91	
OCEB		-10%	-$14.75	-10%	-$14.69	
Total Bill (Including OCEB)			**$132.78**		**$132.22**	**-0.42%**

	General Service Less Than 50 kW					
	Volume	**Current Rates**	**Current Charges ($)**	**Rates as per Acquisition Agreement**	**Charges as per Acquisition Agreement ($)**	**% Change**
Monthly Consumption (kWh)	**2,000**					
Total Loss Factors	**1.0564**					
TOU - Off Peak Consumption	1,352	0.067	90.60	0.067	90.60	
TOU - Mid Peak Consumption	380	0.104	39.55	0.104	39.55	
TOU - On Peak Consumption	380	0.124	47.16	0.124	47.16	
Total: Commodity			**177.31**		**177.31**	**0.00%**
DX Fixed Charge ($)	1	49.98	49.98	49.24	49.24	
DX Fixed Charge Rate Riders ($)	1	5.14	5.14	5.14	5.14	
DX Vol. Charge ($/kWh)	2,000	0.0156	31.2	0.0153	30.60	
DX Vol. Rate Riders ($/kWh)	2,000	-0.0002	-0.4	-0.0002	-0.40	
Low Voltage Vol. Charge ($/kWh)	2,000	0.0008	1.6	0.0008	1.60	
Low Voltage Vol. Rate Riders ($/kWh)	2,000	0.0000	0	0.0000	0.00	
Distribution Base Rates Only			**82.78**		**81.44**	**-1.62%**
Total: Distribution			**87.52**		**86.18**	**-1.53%**
TX-Network ($/kWh)	2,113	0.0062	13.10	0.0062	13.10	
TX-Connection ($/kWh)	2,113	0.0028	5.92	0.0028	5.92	
Total: Transmission			**19.02**		**19.02**	**0.00%**
WMSC ($/kWh)	2,113	0.0044	9.30	0.0044	9.30	
RRRP ($/kWh)	2,113	0.0012	2.54	0.0012	2.54	
DRC ($/kWh)	2,000	0.007	14.00	0.007	14.00	
SSA ($)	1	0.25	0.25	0.25	0.25	
Total: Regulatory			**26.08**		**26.08**	**0.00%**
Total Bill (Before Taxes)			$309.92		$308.58	
HST		13%	$40.29	13%	$40.12	
Total Bill (Including HST)			$350.21		$348.70	
OCEB		-10%	-$35.02	-10%	-$34.87	
Total Bill (Including OCEB)			**$315.19**		**$313.83**	**-0.43%**

	General Service 50 to 4,999 kW					
	Volume	**Current Rates**	**Current Charges ($)**	**Rates as per Acquisition Agreement**	**Charges as per Acquisition Agreement ($)**	**% Change**
Monthly Consumption (kWh)	**47,246**					
Peak (kW)	**100**					
Total Loss Factors	**1.0564**					
Commodity Charges	49,911	0.078	$3,893.03	0.078	$3,893.03	
Total: Commodity			**$3,893.03**		**$3,893.03**	**0.00%**
DX Fixed Charge ($)	1	245.55	$245.55	241.94	$241.94	
DX Fixed Charge Rate Riders ($)	1	-0.10	-$0.10	-0.10	-$0.10	
DX Vol. Charge ($/kW)	100	3.9602	$396.02	3.9019	$390.19	
DX Vol. Rate Riders ($/kW)	100	-0.2764	-$27.64	-0.2764	-$27.64	
Low Voltage Vol. Charge ($/kW)	100	0.3050	$30.50	0.3020	$30.20	
Low Voltage Vol. Rate Riders ($/kW)	100	0.0000	$0.00	0.0000	$0.00	
Distribution Base Rates Only			**$672.07**		**$662.33**	**-1.45%**
Total: Distribution			**$644.33**		**$634.59**	**-1.51%**
TX-Network ($/kW)	100	2.4951	$249.51	2.4951	$249.51	
TX-Connection ($/kW)	100	1.1102	$111.02	1.1102	$111.02	
Total: Transmission			**$360.53**		**$360.53**	**0.00%**
WMSC ($/kWh)	49,911	0.0044	$219.61	0.0044	$219.61	
RRRP ($/kWh)	49,911	0.0012	$59.89	0.0012	$59.89	
DRC ($/kWh)	47,246	0.007	$330.72	0.007	$330.72	
SSA ($)	1	0.25	$0.25	0.25	$0.25	
Total: Regulatory			**$610.47**		**$610.47**	**0.00%**
Total Bill (Before Taxes)			$5,508.36		$5,498.62	
HST		13%	$716.09	13%	$714.82	
Total Bill (Including HST)			$6,224.45		$6,213.45	
OCEB		0%	$0.00	0%	$0.00	
Total Bill (Including OCEB)			**$6,224.45**		**$6,213.45**	**-0.18%**

	Unmetered Scattered Load					
	Volume	Current Rates	Current Charges ($)	Rates as per Acquisition Agreement	Charges as per Acquisition Agreement ($)	% Change
Monthly Consumption (kWh)	**500**					
Total Loss Factors	**1.0564**					
Commodity Charges	528	0.078	41.20	0.078	41.20	
Total: Commodity			**41.20**		**41.20**	**0.00%**
DX Fixed Charge ($)	1	15.49	15.49	15.27	15.27	
DX Fixed Charge Rate Riders ($)	1	0.00	0.00	0.00	0.00	
DX Vol. Charge ($/kWh)	500	0.0087	4.35	0.0086	4.30	
DX Vol. Rate Riders ($/kWh)	500	-0.0007	-0.35	-0.0007	-0.35	
Low Voltage Vol. Charge ($/kWh)	500	0.0008	0.40	0.0008	0.40	
Low Voltage Vol. Rate Riders ($/kWh)	500	0.0000	0.00	0.0000	0.00	
Distribution Base Rates Only			**20.24**		**19.97**	**-1.33%**
Total: Distribution			**19.89**		**19.62**	**-1.36%**
TX-Network ($/kWh)	528	0.0062	3.27	0.0062	3.27	
TX-Connection ($/kWh)	528	0.0028	1.48	0.0028	1.48	
Total: Transmission			**4.75**		**4.75**	**0.00%**
WMSC ($/kWh)	528	0.0044	2.32	0.0044	2.32	
RRRP ($/kWh)	528	0.0012	0.63	0.0012	0.63	
DRC ($/kWh)	500	0.007	3.50	0.007	3.50	
SSA ($)	1	0.25	0.25	0.25	0.25	
Total: Regulatory			**6.71**		**6.71**	**0.00%**
Total Bill (Before Taxes)			$72.55		$72.28	
HST		13%	$9.43	13%	$9.40	
Total Bill (Including HST)			$81.98		$81.68	
OCEB		-10%	-$8.20	-10%	-$8.17	
Total Bill (Including OCEB)			**$73.78**		**$73.51**	**-0.37%**

	Sentinel Lighting					
	Volume	**Current Rates**	**Current Charges ($)**	**Rates as per Acquisition Agreement**	**Charges as per Acquisition Agreement ($)**	**% Change**
Monthly Consumption (kWh)	**108**					
Peak (kW)	**0.3**					
Total Loss Factors	**1.0564**					
Commodity Charges	114	0.078	$8.90	0.078	$8.90	
Total: Commodity			**$8.90**		**$8.90**	**0.00%**
DX Fixed Charge ($)	1	6.53	$6.53	6.44	$6.44	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	
DX Vol. Charge ($/kW)	0.3	19.4330	$5.83	19.1468	$5.74	
DX Vol. Rate Riders ($/kW)	0.3	-0.1359	-$0.04	-0.1359	-$0.04	
Low Voltage Vol. Charge ($/kW)	0.3	0.2407	$0.07	0.2383	$0.07	
Low Voltage Vol. Rate Riders ($/kW)	0.3	0.0000	$0.00	0.0000	$0.00	
Distribution Base Rates Only			**$12.43**		**$12.26**	**-1.42%**
Total: Distribution			**$12.39**		**$12.21**	**-1.43%**
TX-Network ($/kW)	0.3	1.8913	$0.57	1.8913	$0.57	
TX-Connection ($/kW)	0.3	0.8762	$0.26	0.8762	$0.26	
Total: Transmission			**$0.83**		**$0.83**	**0.00%**
WMSC ($/kWh)	114	0.0044	$0.50	0.0044	$0.50	
RRRP ($/kWh)	114	0.0012	$0.14	0.0012	$0.14	
DRC ($/kWh)	108	0.007	$0.76	0.007	$0.76	
SSA ($)	1	0.25	$0.25	0.25	$0.25	
Total: Regulatory			**$1.64**		**$1.64**	**0.00%**
Total Bill (Before Taxes)			$23.77		$23.59	
HST		13%	$3.09	13%	$3.07	
Total Bill (Including HST)			$26.86		$26.66	
OCEB		-10%	-$2.69	-10%	-$2.67	
Total Bill (Including OCEB)			**$24.17**		**$23.99**	**-0.74%**

	Street Lighting					
	Volume	Current Rates	Current Charges ($)	Rates as per Acquisition Agreement	Charges as per Acquisition Agreement ($)	% Change
Monthly Consumption (kWh)	**66**					
Peak (kW)	**0.2**					
Total Loss Factors	**1.0564**					
Commodity Charges	70	0.078	$5.44	0.078	$5.44	
Total: Commodity			**$5.44**		**$5.44**	**0.00%**
DX Fixed Charge ($)	1	1.97	$1.97	1.94	$1.94	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	
DX Vol. Charge ($/kW)	0.2	7.4269	$1.49	7.3175	$1.46	
DX Vol. Rate Riders ($/kW)	0.2	-0.2347	-$0.05	-0.2347	-$0.05	
Low Voltage Vol. Charge ($/kW)	0.2	0.2358	$0.05	0.2334	$0.05	
Low Voltage Vol. Rate Riders ($/kW)	0.2	0.0000	$0.00	0.0000	$0.00	
Distribution Base Rates Only			**$3.50**		**$3.45**	**-1.49%**
Total: Distribution			**$3.46**		**$3.40**	**-1.52%**
TX-Network ($/kW)	0.2	1.8818	$0.38	1.8818	$0.38	
TX-Connection ($/kW)	0.2	0.8583	$0.17	0.8583	$0.17	
Total: Transmission			**$0.55**		**$0.55**	**0.00%**
WMSC ($/kWh)	70	0.0044	$0.31	0.0044	$0.31	
RRRP ($/kWh)	70	0.0012	$0.08	0.0012	$0.08	
DRC ($/kWh)	66	0.007	$0.46	0.007	$0.46	
SSA ($)	1	0.25	$0.25	0.25	$0.25	
Total: Regulatory			**$1.10**		**$1.10**	**0.00%**
Total Bill (Before Taxes)			$10.54		$10.49	
HST		13%	$1.37	13%	$1.36	
Total Bill (Including HST)			$11.92		$11.86	
OCEB		-10%	-$1.19	-10%	-$1.19	
Total Bill (Including OCEB)			**$10.72**		**$10.67**	**-0.50%**

	Embedded Distributors					
	Volume	**Current Rates**	**Current Charges ($)**	**Rates as per Acquisition Agreement**	**Charges as per Acquisition Agreement ($)**	**% Change**
Monthly Consumption (kWh)	**500,000**					
Total Loss Factors	**1.0564**					
Commodity Charges	528200	0.000	0.00	0.000	0.00	
Total: Commodity			**0.00**		**0.00**	
DX Fixed Charge ($)	1	616.86	616.86	607.77	607.77	
DX Fixed Charge Rate Riders ($)	1	0.00	0.00	0.00	0.00	
DX Vol. Charge ($/kWh)	500,000	0.0000	0.0000	0.0000	0.0000	
DX Vol. Rate Riders ($/kWh)	500,000	-0.0009	-450.00	-0.0009	-450.00	
Distribution Base Rates Only			616.86		607.77	**-1.47%**
Total: Distribution			**166.86**		**157.77**	**-5.45%**
TX-Network ($/kWh)	528,200	0.0000	0.00	0.0000	0.00	
TX-Connection ($/kWh)	528,200	0.0000	0.00	0.0000	0.00	
Total: Transmission			**0.00**		**0.00**	
WMSC ($/kWh)	0	0.0044	0.00	0.0044	0.00	
RRRP ($/kWh)	0	0.0012	0.00	0.0012	0.00	
DRC ($/kWh)	0	0.007	0.00	0.007	0.00	
SSA ($)	0	0.25	0.00	0.25	0.00	
Total: Regulatory			**0.00**		**0.00**	
Total Bill (Before Taxes)			$166.86		$157.77	
HST		13%	$21.69	13%	$20.51	
Total Bill (Including HST)			$188.55		$178.28	
OCEB		0%	$0.00	0%	$0.00	
Total Bill (Including OCEB)			**$188.55**		**$178.28**	**-5.45%**