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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

September 30, 2011

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

Dear Ms. Walli

EB-2011-0268– Adjustment to Hydro One Networks' Approved 2012 Electricity Transmission Revenue Requirement To Reflect Adoption of US GAAP - Hydro One Interrogatory Responses

Please find attached an electronic copy of responses provided by Hydro One Networks to Interrogatory questions. Two (2) hard copies will be sent to the Board on the morning of October 3, 2011.

Below is the Tab numbers for each intervenor

Tab	Intervenor
1	Ontario Energy Board
2	London Property Management Association
3	Association of Major Power Consumers in Ontario
4	Vulnerable Energy Consumers Coalition

An electronic copy of the Interrogatories, have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

c. EB-2011-0268 - Intervenors (electronic only)

Ontario Energy Board (Board Staff) INTERROGATORY #1 List 1

Interrogatory

Ref: Exhibit C1/Tab1/Sch2

The approximate $200 million increase in OM&A – the impact of certain overheads not capitalized in the 2010 Transmission decision (EB-2010-0002) – is proposed to be reversed in this application, as per Table 1 Exhibit C1/Tab1/Sch2/pp1&2. This will work to increase capital expenditures by about $200 million in 2012.

i) Regarding Hydro One's current proposal to reduce 2012 OM&A by $200 million: Are there any debits or credits formerly included in 2012 OM&A (using IFRS principles) that would not be allowed under US GAAP rules? Please explain and estimate the amounts of these debits or credits.

ii) Regarding Hydro One's current proposal to increase 2012 rate base by $200 million: Are there any debits or credits formerly not included in 2012 rate base (using IFRS principles) that would not be allowed under US GAAP rules? Please explain and estimate the amounts of these debits or credits.

Response

i) No. Hydro One has not identified any debits or credits formerly included in 2012 OM&A under IFRS principles that would not be allowed as OM&A expense under US GAAP.

ii) No. Hydro One has not identified any debits or credits formerly included as 2012 capital expenditures under IFRS principles that would not be allowed as capital expenditures under US GAAP.

Ontario Energy Board (Board Staff) INTERROGATORY #2 List 1

Interrogatory

Ref: Exhibit A/Tab2/Sch1/p.2

With reference to the proposed reduction in 2012 revenue requirement, please provide an estimated bill impact change (as provided in previous transmission rate cases). Please include all assumptions and appropriate detail.

Response

Customer Bill Impact of Transmission Revenue Requirement Change

The estimated average increase on total customer bill in 2012 was 2.0% per the approved Rate Order in EB-2010-0002[1], and is estimated to be 0.9% based on the reduction in Rates Revenue Requirement requested in this EB-2011-0268 proceeding.

For a typical residential customer consuming 800 kWh per month, the estimated increase in the customer's total monthly bill in 2012 was $2.48 per the approved Rate Order in EB-2010-0002[1], and is estimated to be $1.07 based on the reduction in Rates Revenue Requirement requested in this application.

Estimated Impact of Transmission (Tx) Revenue Requirement Increase on Total Bill:

		per EB-2010-0002 Rate Order[1]		**per EB-2011-0268 Proceeding**
		2011	**2012**	**2012**
Rates Revenue Requirement		1,299.5	1,626.8	1,431.5[2]
2012 increase over 2011	A		25.2%	10.2%
Load Reduction % impact	B		1.2%	1.2%
Total Tx Rate Impact	A+B		26.4%	11.4%
Tx as a % of Total Bill	C		7.5%	7.5%
Total Bill Impact	**(A+B)xC**		**2.0%**	**0.9%**

[1] Per Transmission Rate Order approved in EB-2010-0002 [submitted in EB-2011-0268 evidence as C1-2-1]. Please note that as per the OEB Decision in EB-2010-0002, the 2012 Cost of Capital is to be updated in the Fall of 2011 to reflect OEB approved parameters, 2011 actual debt issuances and updated forecast 2012 third-party long-term debt rates.

[2] Per Exhibit C1, Tab 1, Schedule 2 , Table 1

Estimated Monthly Increase in Retail Transmission Service Rate (RTSR) Charges on Total Bill for Typical Residential Customer Consuming 800 kWh per month:

		EB-2010-0002 Rate Order[2]	**EB-2011-0268 Application**
2010 Monthly RTSR Charge (1.049 ¢/kWh x 868 kWh)[1]	A	$9.11	$9.11
Hydro One Tx Share of Uniform Transmission Rates[2]	B	0.96611	0.96611
2011 Tx Rate Impact[2]	C	7.0%	7.0%
RTSR Charges in 2011	D=Ax(1+CxB)	$9.72	$9.72
2012 Tx Rate Impact	E	26.4%	11.4%
RTSR Charges in 2012	F=Dx(1+ExB)	$12.20	$10.79
Increase in 2012 RTSR Charges	**F-D**	**$2.48**	**$1.07**

[1] Per 2010 Distribution Rate Schedule for Medium Density (R1) Residential Customer approved in EB-2009-0096.

[2] Per Transmission Rate Order approved in EB-2010-0002 [submitted in EB-2011-0268 evidence as C1-2-1]. Please note that as per the OEB Decision in EB-2010-0002, the 2012 Cost of Capital is to be updated in the Fall of 2011 to reflect OEB approved parameters, 2011 actual debt issuances and updated forecast 2012 third-party long-term debt rates.

Customer Bill Impact of Distribution Revenue Requirement Change

As outlined in Exhibit I, Tab 1, Schedule 3, the use of US GAAP in place of MIFRS will also result in a significant decrease in Hydro One Networks' Distribution revenue requirement. Specifically, the 2012 Distribution base rates would increase by 14% if MIFRS were utilized rather than US GAAP. If all other items on the current customer bill stay the same, for Distribution, the utilization of MIFRS rather than US GAAP would result in an increase of $6.59/month or 5.0% on total bill in the 2012 Total Bill for a typical residential customer (R1) consuming 800 kWh per month. The calculations are provided as Attachment1.

Hydro One Medium Density (R1) Residential Customer Charges as of May 1, 2011

kWh Consumption					800
Total Loss Factor					1.085
Wholesale kWhrs					868
Bill calculation	**Tariff**	**Units**	**Determinant**		
1. Commodity Charge	6.80	¢/kWh	868	kWhrs	$59.02
2. Dx Charges					
volumetric charge - base	3.317	¢/kWh	800	kWhrs	$26.54
Volumetric charge - riders	-0.050		800		($0.40)
fixed charge - base	$19.72				$19.72
fixed charge - adders/riders	$4.27				$4.27
Transmission (RTSR)	$1.05		868	kWhrs	$9.11
3. Other Regulated Charges					
WMSC	0.52	¢/kWh	868	kWhrs	$4.51
RRRP	0.13	¢/kWh	868	kWhrs	$1.13
SSS	$0.25				$0.25
Debt Retirement Charge	0.70	¢/kWh	800	kWhrs	$5.60
4. Total Charge excluding HST					$129.75
5. HST					$16.87
6. Total Charge including HST					$146.61
7. OCEB					$14.66
8. TOTAL BILL					**$131.95**

Hydro One Medium Density (R1) Residential Customer Charges as of May 1, 2011 assuming an increase in Distribution base rates of 14%

kWh Consumption					800		
Total Loss Factor					1.085		
Wholesale kWhrs					868		
Bill calculation	**Tariff**	**Units**	**Determinant**				
1. Commodity Charge	6.80	¢/kWh	868	kWhrs	$59.02		
2. Dx Charges							
volumetric charge - base	3.781	¢/kWh	800	kWhrs	$30.25		
Volumetric charge - riders	-0.050		800		($0.40)		
fixed charge - base	$22.48				$22.48		
fixed charge - adders/riders	$4.27				$4.27		
Transmission (RTSR)	$1.05		868	kWhrs	$9.11		
3. Other Regulated Charges							
WMSC	0.52	¢/kWh	868	kWhrs	$4.51		
RRRP	0.13	¢/kWh	868	kWhrs	$1.13		
SSS	$0.25				$0.25		
Debt Retirement Charge	0.70	¢/kWh	800	kWhrs	$5.60		
4. Total Charge excluding HST					$136.22		
5. HST					$17.71		
6. Total Charge including HST					$153.93		
7. OCEB					$15.39	$ increase	% increase
8. TOTAL BILL					**$138.54**	$6.59	5.0%

Ontario Energy Board (Board Staff) INTERROGATORY #3 List 1

Interrogatory

Ref: Exhibit A/Tab2/Sch1/p.2

Hydro One seeks acknowledgement and approval that if US GAAP is approved for Hydro One Transmission rates, that it is appropriate for Hydro One to also use US GAAP for Distribution rates. Please provide an estimate of how a notional Hydro One distribution revenue requirement will be affected by replacing MIFRS with US GAAP. Please provide a detailed impact on Capital Expenditures, OM&A levels, Rate Base, PILs and Revenue Requirement.

Response

Please find below the estimate of how a notional Hydro One Distribution revenue requirement will be affected by replacing MIFRS with US GAAP. Directionally the impact on Hydro One Distribution of this change in accounting principles is the same as it is for Hydro One Transmission; specifically Distribution Revenue Requirement and rates go down substantially if MIFRS is replaced by US GAAP.

Difference Between USGAAP and MIFRS [M$]

USGAAP is higher/(lower) versus MIFRS	2012
OM&A	(170)
Depreciation	3
Return on rate base	3
PILs	(2)
Annual Revenue Requirement–US GAAP	(166)
Capital Expenditures	170
Rate Base	33

A change to US GAAP would result in an approximate rate impact of -14% in 2012 as compared to MIFRS.

The total customer bill impact in 2012 of this change is provided as the second part of Exhibit 1, Tab 1, Schedule 2.

Ontario Energy Board (Board Staff) INTERROGATORY #4 List 1

Interrogatory

Ref: Exhibit A/Tab3/Sch1/p1

Hydro One states that, "In May 2011 it became known that there was an option for rate regulated entities to apply to its securities regulator for an exemption to permit use of US GAAP for the preparation of financial statements." EB-2011-0268 Hydro One Networks Inc. 2012 Transmission Rates, US GAAP Board Staff Interrogatories

i) What event occurred in May 2011?
ii) Had Hydro One not contemplated the use of US GAAP before this time? For example, in the fall of 2010 before the Board's EB-2010-0002 decision?

Response

i) In May 2011, Hydro One became aware of the Enbridge Income Fund application to its relevant securities regulators [refer to Exhibit B, Tab 1, Schedule 2, page 1].

ii) In the fourth quarter of 2010, after the International Accounting Standards Board (IASB) withdrew its exposure draft on Rate Regulated Accounting, it decided that further work on regulatory accounting was justified through future projects. However, this initiative is not on the list of IASB's priority projects in its work plan. As a result the Canadian Accounting Standards Board (AcSB) finalized a one-year optional IFRS deferral for rate-regulated entities until January 1, 2012 which Hydro One elected to adopt.

    The Company in December 2010 started working closely with the Canadian Electricity Association and the Canadian accounting firms in reviewing various fact patterns for regulatory accounting in Canada but it was concluded that rate regulated accounting could not be accommodated under IFRS. With certainty that no further guidance regarding rate-regulated accounting would be available in time in 2012 for IFRS adoption, in early 2011 the Company began evaluating options for reporting under US GAAP until such time as the Enbridge Income Fund decision became known. Based on this precedent case Hydro One decided to adopt US GAAP as an optional reporting framework. Hydro One was granted its exemption by the OSC on July 21, 2011.

Ontario Energy Board (Board Staff) INTERROGATORY #5 List 1

Interrogatory

Ref: Exhibit A/Tab3/Sch1/p.4

At Line 16, Hydro One indicates that use of US GAAP for regulatory purposes is in the best interests of all stakeholders. Please provide further details backing up this assertion, listing specific stakeholders and how their interests are best served under US GAAP rather than MIFRS.

Response

The significant stakeholders of Hydro One Networks' Transmission and Distribution businesses are: Electricity customers; the Province of Ontario, the parent Company's sole shareholder; and the external financial community, including investors.

Customers benefit from continued rate stability under US GAAP given that it is very similar to CGAAP. As rate regulated accounting continues to be recognized under US GAAP, the regulator may be more inclined to utilize deferral and variance accounts in conjunction with rate riders/adders to achieve rate smoothing. Further, significant transmission and distribution rate increases that result from the adoption of MIFRS will be avoided under US GAAP. In addition, increased costs of regulatory compliance are avoided through the adoption of US GAAP for both regulatory and external financial reporting purposes since the Company will not have to duplicate transactional accounting in two sets of books and reconcile between them. In addition, a single accounting model avoids increased costs related to duplicating information systems and audit work.

The Province of Ontario has an over riding interest in promoting the cost-effective supply of electricity to industry and retail customers. In this regard, the use of US GAAP in lieu of IFRS and the resultant lower electricity rates support Provincial economic priorities. Further, the transition to IFRS would result in significant de-recognition of Hydro One's regulatory assets and liabilities which would be charged to retained earnings. Under IFRS, on consolidation, the Province's retained earnings would be in the range of $2 billion lower than they would be under US GAAP.

From an external investor and supporting financial analyst's perspective, alignment of the accounting frameworks in use for external financial reporting and for rate making provides a clearer and more understandable relationship between the accounting basis used to set rates and that used to report results. This alignment better depicts the link between cash flows stemming from the regulatory process and the underlying accounting basis. Further, the volatility in annual net income that would result under an IFRS regime (through immediate recognition in net income of changes in pension liability for example) and the resulting clouding of the Company's underlying economic fundamentals, would be avoided under a US GAAP framework.

Ontario Energy Board (Board Staff) INTERROGATORY #6 List 1

Interrogatory

Ref: Ontario Regulation 395/11

Ontario Regulation 395/11 requires that Hydro One Inc. prepare its financial statements in accordance with US GAAP for any financial year on or after January 1, 2012.

i) Please file a copy of this Regulation.
ii) Please confirm that this Regulation is now in force.
iii) Please confirm that there is no time limitation on the use of US GAAP in the Regulation.

Response

i) A copy of the Regulation is provided as Attachment 1. It can also be found at the following link:

http://www.e-laws.gov.on.ca/html/regs/english/elaws_regs_110395_e.htm

ii) So confirmed.

iii) So confirmed.

Filed: September 30, 2011
EB-2011-0268
Exhibit I-1-6
Attachment 1

Ontario

ServiceOntario
e-Laws

Français

Financial Administration Act

ONTARIO REGULATION 395/11

ACCOUNTING POLICIES AND PRACTICES

Consolidation Period: From August 31, 2011 to the e-Laws currency date.

No amendments.

This is the English version of a bilingual regulation.

PUBLIC ENTITIES

Depreciable tangible capital assets, etc.

1. (1) In its accounts, a public entity shall recognize the following items as deferred capital contributions:

1. Contributions received or receivable by the public entity for the purpose of acquiring or developing a depreciable tangible capital asset for use in providing services.
2. Contributions in the form of depreciable tangible assets received or receivable by the public entity for use in providing services. O. Reg. 395/11, s. 1 (1).

(2) In its accounts, a public entity shall reduce its liability for deferred capital contributions in respect of a depreciable tangible capital asset at the same rate as the rate at which amortization is recognized in respect of the asset, and shall account for the reduction of the liability in the periods during which the asset is used to provide services. O. Reg. 395/11, s. 1 (2).

(3) In its accounts, a public entity shall recognize, as revenue, the capital contributions in respect of a depreciable tangible capital asset at the same rate as the rate at which amortization is recognized in respect of the asset, and shall account for the revenue in the periods during which the asset is used to provide services. O. Reg. 395/11, s. 1 (3).

(4) If the net book value of a depreciable tangible capital asset is reduced for any reason other than amortization, a public entity shall, in its accounts, recognize a proportionate reduction of the deferred capital contributions for the asset and a proportionate increase in the revenue from deferred capital contributions for the asset. O. Reg. 395/11, s. 1 (4).

(5) This section prevails over a requirement of another Act or regulation. O. Reg. 395/11, s. 1 (5).

OTHER ENTITIES

Hydro One Inc.

2. (1) Hydro One Inc. shall prepare its financial statements in accordance with U.S. generally accepted accounting principles. O. Reg. 395/11, s. 2 (1).

(2) This section applies for any financial year of Hydro One Inc. that begins on or after January 1, 2012. O. Reg. 395/11, s. 2 (2).

(3) This section prevails over a requirement of another Act or regulation. O. Reg. 395/11, s. 2 (3).

3. Omitted (provides for coming into force of provisions of this Regulation). O. Reg. 395/11, s. 3.

Français

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Ontario Energy Board (Board Staff) INTERROGATORY #7 List 1

Interrogatory

Ref: Exhibit B/Tab1/Sch1: Ontario Securities Commission decision, July 21, 2011

Please confirm that the exemption granted in this decision expires on December 31, 2014.

Response

So confirmed.

Ontario Energy Board (Board Staff) INTERROGATORY #8 List 1

Interrogatory

Ref: Exhibit B/Tab 1/Sch2/p. 1 Letter of July 7, 2011 from Osler to the Ontario Securities Commission

Hydro One requested a 3 year exemption from the OSC from January 1, 2012 to January 1, 2015. Why did Hydro One choose a 3 year exemption? What factors were considered in applying for this time period? Were certain issues anticipated to be resolved in that time frame?

Response

Hydro One chose to request a three-year exemption request based on the term of the Enbridge Income Fund precedent [refer to Exhibit B, Tab 1, Schedule 2, page 1] and advice from advisors that this was the term that was likely to receive regulatory approval.

Ontario Energy Board (Board Staff) INTERROGATORY #9 List 1

Interrogatory

Ref: Exhibit B/Tab1/Sch2/p.9: Letter of July 7, 2011 from Osler to the Ontario Securities Commission

At paragraph 38, the evidence states,

> "The Exemption Sought would permit the Filer to use US GAAP for three financial years, commencing on January 1, 2012. This will allow the securities regulatory authorities to assess the consequences of granting the Exemption Sought in light of subsequent developments, including the potential for express recognition of rate regulated accounting under IFRS coincident with the adoption of IFRS in the United States… In short, the proposed sunset provision in the Exemption Sought provides not only the securities regulatory authorities, but also the Filer, with time to evaluate alternatives and determine the best way to proceed in light of the significant ramifications for the Filer of adopting IFRS, as currently formulated."

Ref: Exhibit C/Tab1/Sch1/p. 4
At this reference, the evidence states,

> "Hydro One notes that those who are involved in setting standards for US and international accounting are working closely together, and expect to do so more significantly in the future. As a result of this cooperative effort, US and international accounting frameworks continue to converge. The use of rate-regulated accounting remains as one of the few major differences requiring resolution."

i) When is the United States scheduled to adopt IFRS?

ii) Board staff notes the May 26, 2011 U.S. Securities and Exchange Commission Staff Paper entitled: "Work Plan for the Consideration of Incorporating International Financial Reporting Standards into the Financial Reporting System for U.S. Issuers, Exploring a Possible Method of Incorporation."[1] On page 1 of this paper it is stated: "The Commission has not yet made a decision as to whether and, if so, how, to incorporate IFRS into the financial reporting system for U.S. issuers."

If the US determines not to adopt IFRS but continues to use US GAAP, would Hydro One seek a further exemption from the OSC for reporting years subsequent to 2014?

iii) Please provide the basis for the following statements, including references to supporting material (e.g. the Securities and Exchange Commission website):

- Those who are involved in setting standards for US and international accounting are working closely together.

- Those who are involved in setting standards for US and international accounting expect to work closely together more significantly in the future.

iv) Please provide examples of recent convergence of US and international accounting frameworks, particularly with respect to rate-regulated accounting.

[1] http://www.sec.gov/spotlight/globalaccountingstandards/ifrs-work-plan-paper-52611.pdf

Response

i) There is currently no formal or approved schedule for the United States to adopt IFRS.

ii) If the US determines not to adopt IFRS but continues to use US GAAP, Hydro One would intend to seek a further exemption from the OSC for reporting years subsequent to 2014.

iii) In support of the above statements:

> "The IASB and the US Financial Accounting Standards Board (FASB) have been working together since 2002 to achieve convergence of IFRSs and US generally accepted accounting principles (GAAP). A common set of high quality global standards remains a priority of both the IASB and the FASB". Source: www.IFRS.org

> "The FASB continues to aggressively pursue the goal of a single set of high-quality accounting standards with the International Accounting Standards Board (IASB), as evidenced by intensified work efforts between the two Boards on the convergence projects identified in the Memorandum of Understanding (MoU) with the IASB." Source: www.fasb.org

> "As the FASB aims to complete in 2011 the important projects identified in our MoU with the IASB, we expect 2010 to be a pivotal year of progress. As our shared standard-setting goals continue with the IASB, the FASB will maintain a priority for the pursuit of improvement in standards, an essential ingredient for the completion of MoU projects and a focus also underscored in the work plan in the segment entitled “Sufficient Development and

Application of IFRS for the U.S. Domestic Reporting System." The FASB will continue to address reporting issues of critical importance to U.S. investors and financial markets while pursuing the international standard setting agenda." Source: www.fasb.org

"Progress toward this goal <the move toward global standards> has been steady. All major economies have established time lines to converge with or adopt IFRSs in the near future. The international convergence efforts of the organisation are also supported by the Group of 20 Leaders (G20) who, at their September 2009 meeting in Pittsburgh, US, called on international accounting bodies to redouble their efforts to achieve this objective within the context of their independent standard-setting process. In particular, they asked the IASB and the US FASB to complete their convergence project by June 2011. " Source: www.IFRS.org

iv) There have not been any significant recent developments affecting the convergence of rate regulated accounting between the FASB and ISB. Nor has the IASB carried out any significant work on its own rate regulated accounting project.

The recently completed joint projects include "Financial Statement Presentation". On 16 June, 2011 the IASB issued amendments to IAS 1 Financial Statement Presentation. These amendments improve how components of other comprehensive income are presented. The FASB issued equivalent requirements on the same day. In another joint project, the IASB and FASB undertook a consultation seeking respondents' views on whether or how to sequence effective dates for IFRSs issued in 2011, to help reduce the cost of implementing the new requirements. In November 2010, the IASB and FASB decided to amend the timetable for joint projects that are important but less urgent. The projects affected are Financial Statement Presentation, Financial Instruments with Characteristics of Equity, Emissions Trading Schemes, Liabilities and Income Taxes. The IASB will review these projects as part of its agenda consultation process, at the beginning of 2012.

The IASB completed Phase A of its Conceptual Framework Project by publishing in September 2010 the Objectives and Qualitative characteristics chapters of the new Conceptual Framework. The IASB and the FASB will amend sections of their conceptual frameworks as they complete individual phases of the project.

Ontario Energy Board (Board Staff) INTERROGATORY #10 List 1

Interrogatory

Ref: EB-2008-0408 Addendum to Report of the Board, June 13, 2011
At page 19 of this Report, the Board indicates:

> "The Board cautions utilities that the adoption of USGAAP as a short term solution may be counter-productive. If a utility is required to transition to IFRS for financial reporting purposes a few years after adopting USGAAP, certain transitional issues may not have been avoided, but delayed…"

i) Please describe what indications exist to suggest that IAS16 will change sufficiently to avoid the problematic consequences of each of the three issues Hydro One identifies: capitalization, depreciation and recognition of regulatory assets.

ii) Board staff notes the IASB's most recently published Work Plan[2], which does not list rate-regulated activities as an active project in 2011 or 2012. Does Hydro One believe that the necessary work will be completed by accounting standards bodies to resolve the issues surrounding the use of rate-regulated accounting under IFRS by December 31, 2014?

If yes, please provide a summary of, or references to information from those accounting standards bodies that support that belief.

iii) If the issues surrounding rate-regulated accounting under IFRS are not resolved by the time the exemption granted by the OSC expires, what action does Hydro One propose to take? Please explain the rationale for the proposed action.

[2] http://www.ifrs.org/NR/rdonlyres/C206BF1D-03CA-4B0F-831E-DA172F2466C6/0/Workplan14September2011.pdf

Response

i) There are currently no indications to suggest that IAS16 will change to avoid the problematic consequences of each of the three issues Hydro One identified should a move to MIFRS ultimately occur for rate setting purposes.

ii) Based on the absence of a formal plan, available time and normal standard setting process timeframes, Hydro One does not expect that the International Accounting Standards Board will resolve the rate regulated accounting issue before 2015.

iii) If the issues surrounding rate-regulated accounting under IFRS are not resolved by the time the exemption granted by the OSC expires, Hydro One would likely apply to the OSC for an extension of the present exemption with appropriate lead time.

Ontario Energy Board (Board Staff) INTERROGATORY #11 List 1

Interrogatory

Ref: EB-2008-0408 Addendum to Report of the Board, June 13, 2011

The Board's Addendum, in Issue 2, makes provision for a Property Plant and Equipment deferral account to capture certain differences arising from the transition to IFRS. The Board notes at page 19 of the Addendum that the account may not be necessary for utilities that adopt US GAAP rather than IFRS. Does Hydro One intend to make use of the Property, Plant and Equipment deferral account? If yes, please explain why the account is necessary and provide an estimate of the amounts that would be captured in the account.

Response

Hydro One Networks does not intend to make use of this Property, Plant and Equipment deferral account if US GAAP is adopted for rate making purposes.

Ontario Energy Board (Board Staff) INTERROGATORY #12 List 1

Interrogatory

Ref: Exhibit B/Tab2/Sch2 Hydro One July 15, 2011 Letter
On page 2 of this letter Hydro One asserts that there would be reduced costs if a consistent accounting framework were used. Please describe in detail the additional costs Hydro One would incur were the Board to require Hydro One to use MIFRS for rate applications and regulatory filing, while Hydro One Inc. is required to use US GAAP.

Response

Hydro One has determined that the adoption of US GAAP and use of a single accounting framework for external financial reporting and rate setting will avoid additional costs that would accompany using two sets of books to reflect US GAAP and MIFRS. The Company has not prepared a comprehensive list of all such costs but some examples include:

- Transactional accounting - Internal and through its outsourcing partner;
- Preparation of accounting reconciliations – US GAAP vs MIFRS;
- Accounting policy guidance and development;
- Development and maintenance of accounting processes;
- Training for management, finance and other staff;
- Incremental external assurance costs;
- Regulatory and planning costs;
- IT system – ledger customization and development, dual reporting, additional internal controls etc.
- Tax Department costs.

Ontario Energy Board (Board Staff) INTERROGATORY #13 List 1

Interrogatory

Ref: Exhibit B/Tab2/Sch2, Hydro One July 15, 2011 Letter

i) What are Hydro One's costs of transitioning to US GAAP? Please provide detailed estimates.

ii) If Hydro One transitions to IFRS for January 1, 2015, what are the estimated costs of that transition?

Response

i) Hydro One does not have detailed estimates of the future costs of transitioning to US GAAP available but does not expect that incremental costs will be significant.

ii) Hydro One cannot forecast the future costs to transition to IFRS for January 1, 2015 should that occur given uncertainty regarding IFRS and US GAAP developments occurring over the future period. However, Hydro One's IFRS conversion effort was substantially completed in 2011 and the project has been mothballed in an orderly fashion that will allow an orderly future restart. Hydro One would not expect to duplicate any IFRS conversion costs already incurred. There may be some new work required to address any new IFRSs becoming effective in the period preceding adoption.

Ontario Energy Board (Board Staff) INTERROGATORY #14 List 1

Interrogatory

Ref: Exhibit C/Tab1/Sch1/pp. 3&4

Hydro One states:

> "In addition, US GAAP allows continued use of group depreciation methods. IAS 16 does not. If US GAAP is approved as Hydro One's regulatory accounting and reporting framework, Hydro One will continue its existing depreciation accounting policies, including the use of group depreciation. This results in depreciation rates and annual depreciation expenses that will be lower over the long run and which more closely reflect the average service life of all in-service assets. This will avoid future rate increases that would accompany the use of item depreciation which does not take into consideration the dispersion of asset expected service lives within a group."

Board staff notes that IAS 16 paragraph 9 states:

> "This Standard does not prescribe the unit of measure for recognition, ie what constitutes an item of property, plant and equipment. Thus, judgement is required in applying the recognition criteria to an entity's specific circumstances. It may be appropriate to aggregate individually insignificant items, such as moulds, tools and dies, and to apply the criteria to the aggregate value."

i) Why would depreciation expense be lower "over the long run" if Hydro One uses US GAAP for regulatory purposes as compared to MIFRS? Please explain and quantify the difference.

ii) Did Hydro One consider using the "vintage basis" of depreciation, in which like assets are categorized together for depreciation purposes and the combined cost of the assets is allocated over their estimated useful life?

iii) Would depreciation expense still be lower under US GAAP if Hydro One used the vintage basis of depreciation, or another similar basis, under MIFRS?

Response

i) A fundamental difference between group accounting under US GAAP and item accounting under IFRS is the treatment of gains or losses upon retirement. The definitional standards of IAS 16 prescribe a system of accounting in which the carrying value (i.e., cost less accumulated depreciation) of a plant item is "derecognized" on disposal or when no further economic benefits are expected from its use. The gain or loss arising from derecognition of a property unit is the difference between the net disposal proceeds, if any, and the carrying amount of the item.

Group depreciation accounting, on the other hand, neither reports nor recognizes gains or losses resulting from the retirement of property units before or after the expiration of an estimated service life. Under–depreciation of property units retired earlier than predicted is offset by over–depreciation of property units remaining in service beyond the estimated average service life of a group. This treatment is consistent with the regulatory principle that opportunities should be preserved for the recovery of capital devoted to public service. The requirement under IAS 16 to recognize gains or losses prohibits accruing depreciation on property units remaining in service beyond an estimated average service life of a group of similar property units within a vintage or an aggregation of property units at a higher level.

The opportunity for capital recovery under item accounting can only be preserved for a regulated entity if losses are recognized as a revenue requirement when no depreciation is accrued for assets remaining in service beyond an estimated service life. This treatment will shift the timing of depreciation relative to group accounting and item accruals will remain higher than group accruals for any open–ended plant account exhibiting retirement dispersion. All plant accounts for Hydro One are open–ended and retirements are distributed both before and after estimated average service lives. Hydro One has not quantified the long–run difference between item and group accounting given the fact that many other US GAAP versus IFRS accounting differences have the potential to impact the difference in long-term depreciation expense under the two accounting frameworks

ii) Although the term “vintage basis” generally refers to a retirement pricing method, the question suggests that “vintage basis” is intended to mean a level of asset grouping. Group depreciation rates currently used by Hydro One were developed from a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. The vintage–group procedure distinguishes average service lives among vintages and provides cost apportionment over the estimated weighted–average remaining life of a rate category. This treatment is equivalent to allocating the cost of each vintage over “their estimated useful life.”

Implementation of an item procedure under IAS 16 would also allocate the cost of each vintage over “their estimated useful life.” The difference between the group and item procedures is the treatment of gains or losses as described in part i) above.

iii) Yes, depreciation expense would still be lower under US GAAP for any open–ended plant account exhibiting retirement dispersion. It is the treatment of gains or losses that shifts the timing of depreciation expense and produces group depreciation rates lower than item rates.

Ontario Energy Board (Board Staff) INTERROGATORY #15 List 1

Interrogatory

Ref: Exhibit B/Tab2/Sch1/p.2

In this letter, Hydro One mentions changes to capitalization from MIFRS to US GAAP. Please provide a table of the specific items that contribute to the change in Rate Base due to adopting US GAAP capitalization rather than MIFRS, including the drivers for the change.

Response

The following table summarizes the specific items that contribute to the change in Rate Base due to adopting US GAAP policies that are consistent with previous CGAAP policies rather than MIFRS.

The single accounting driver for change is that US GAAP has no explicit prohibition against capitalization of certain overhead and indirect costs that exists within IAS 16. With the adoption of US GAAP, Hydro One Networks proposes to return to the basis for the calculation of its 2012 overhead capitalization rate proposed in the original evidence and generally consistent with that used in previous Hydro One Networks Transmission and Distribution applications since the inception of the Company in 1999.

• Shared common corporate functions and services costs
• Field supervision - indirect
• Field – administrative support
• Procurement card expenditures – non project/program
• Discretionary training and health/safety costs [1]
• Fleet – administrative costs
• Employee benefits – past service pension and OPEBs

1. Only those training and health/safety costs directly associated with gaining and maintaining staff accreditation allowing them to work on the electricity system were capitalized under MIFRS.

Ontario Energy Board (Board Staff) INTERROGATORY #16 List 1

Interrogatory

Ref: Exhibit C/Tab1/Sch1/p.3
Please confirm that the third word on line 11 of page 3 should be “indirects”.

Response

So confirmed

Ontario Energy Board (Board Staff) INTERROGATORY #17 List 1

Interrogatory

Ref: Exhibit C/Tab1/Sch1/p.4
Line 15 of this reference states:

> "In the future, once appropriate normalization adjustments have been made, local benchmarking can still take place."

Please describe what normalization adjustments are being referred to.

Response

In the referenced sentence, Hydro One Networks was making the observation that benchmarking between its Distribution business and other Ontario LDCs can still take place once normalization occurs. Additional normalization adjustments would potentially be required (depending on the financial statement item being benchmarked) for US GAAP versus accounting policy differences. For example, adjustments to reported OM&A could be made for differences in capitalization polices under US GAAP and MIFRS. Hydro One Transmission expects that any such adjustments required could reasonably be made on a top-down basis.

Ontario Energy Board (Board Staff) INTERROGATORY #18 List 1

Interrogatory

Ref: Exhibit C1/Tab1/Sch2/p.1

Hydro One shows a $200 million reduction in OM&A for 2012 under the US GAAP scenario. Please provide additional detail on these reductions by major category:

- Sustaining (Stations, Lines, Engineering and Environmental)
- Development (Research, Standards, and Smart Zone)
- Operations (Operations, Operations Support, Environment-Health-Safety Large Customer & Generator Relations)
- Shared Services (CCFS, Asset Management, IT, Cornerstone, Cost of Sales and Other)
- Customer Care
- Taxes (Property Tax, Indemnity Payments and Rights Payments)

Please include the actual amounts by detailed category and an explanation for the reductions due to the application of US GAAP rather than MIFRS.

Response

Hydro One's Transmission and Distribution businesses are proposing to retain their legacy capitalization policy for overheads and other indirect costs under a US GAAP framework. The shift of $200 million of expenditures from OM&A to capital due to the application of US GAAP rather than MIFRS is driven by the fact that US GAAP has no explicit prohibition against capitalization of certain overhead and indirect costs compared to IAS 16. With the adoption of US GAAP, Hydro One Networks proposes to return to the basis for the calculation of its 2012 overhead capitalization rate proposed in the EB-2010-0002 and approved by the Board in previous cost of service proceedings (EB-2006-0501 and EB-2008-0272).

The $200 million shift to OM&A from capital expenditures for 2012 under MIFRS was never calculated in detail by category. The area most impacted by the shift back from OM&A to capital expenditures under US GAAP would be Shared Services (Other) with a reduction of about $120 million, reflective of the capitalized overhead credit which represents the portion of allocated shared corporate and/or business unit functions and services that are deemed through the capital overhead rate to be supportive of capital projects (see Attachment 1 - EB 2010-0002, Exhibit C1, Tab 2, Schedule 7, pages 27, 28). The capitalized overhead costs are distributed to capital projects based on the allocation methodology derived through the accepted Black & Veatch study.

The remainder of the $200 million shift from OM&A to capital expenditures of about $80 million would occur in each of the Sustaining, Development and Operations OM&A categories as it would relate to indirect costs embedded in the labour, fleet and material surcharge rates that now become capitalized under US GAAP.

EB-2010-0002 – EXHIBIT C1, TAB 2, SCHEDULE 7

PAGES 27 AND 28

Fixed facility cost components (for example, utilities, property taxes, operational costs) are expected to continue to rise. The test years indicated funding also takes into consideration changing factors in the operating environment.

2.0 OTHER OM&A

Other OM&A is comprised of Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs as listed in Table 11.

Table 11
Total Transmission Other OM&A ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Capitalized Overhead	(70.4)	(81.0)	(94.7)	(117.8)	(126.3)	(121.1)
Environmental Provision	(5.2)	(3.5)	(2.5)	(5.5)	(7.3)	(7.8)
Indirect Depreciation	(4.1)	(4.1)	(5.2)	(4.6)	(5.1)	(5.0)
Other	7.2	(21.0)	(12.2)	(2.4)	0.4	2.1
Total	(72.5)	(109.6)	(114.6)	(130.3)	(138.3)	(131.8)

2.1 Capitalized Overhead Credit

Table 12
Transmission Corporate Overhead Credit ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Transmission	(70.4)	(81.0)	(94.7)	(117.8)	(126.3)	(121.1)

Capitalized overheads represent that portion of allocated shared corporate and/or business unit functions and services that are deemed through the capital overhead rate to be supportive of Capital projects as opposed to OM&A based projects. These costs are included in shared services and in the lines of businesses. The capital overhead rate determines the costs capitalized. OM&A expense is thus reduced by the capitalized amounts.

The capitalized OM&A costs are distributed to Capital projects based on the allocation methodology derived through the accepted Black & Veatch study (See Exhibit C1, Tab 5, Schedule 1).

2.2 Environmental Provision

Table 13
Transmission Environmental Provision ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Transmission	(5.2)	(3.5)	(2.5)	(5.5)	(7.3)	(7.8)

In 2001, Networks business recognized a liability on its balance sheet for the present value of future estimated environmental expenditures necessary to deal with legacy contaminated lands and the implementation of remedial measures to treat, remove or otherwise manage the contamination. The change in accounting policy from the previous as-incurred basis was adopted to align with the theoretically stronger U.S. generally accepted accounting principle that was expected to be imminent in Canada. Environmental work is initially recognized in the sustaining work program. The amount is then removed from OM&A and the liability / provision is amortized by the amount of the expenditures incurred. The resultant impact on OM&A expense of this environmental work is nil, since the amortization expense is grouped with 'Depreciation and

Ontario Energy Board (Board Staff) INTERROGATORY #19 List 1

Interrogatory

Ref: Exhibit D1/Tab1/Sch1/p.1

Hydro One has requested that three Regulatory Asset accounts be discontinued. Please indicate if any amounts have been entered into these accounts and if so, how Hydro One proposes to deal with these account balances. Please state if any of the balances that were entered into these accounts have been incorporated into the proposed revenue requirement in this application.

Response

As all three Regulatory Asset Accounts were approved effective January 1, 2012, Hydro One has not entered any amounts into these Regulatory Asset Accounts proposed to be discontinued.

Ontario Energy Board (Board Staff) INTERROGATORY #20 List 1

Interrogatory

Ref: Exhibit D1/Tab1/Sch1/p.3 IFRS – Incremental Transition Costs Account

i) Please indicate if any entries have been made to this account and the rationale for making these entries, and report the current balances as of June 30, 2011. Please state the amount of IFRS Transition Costs that were embedded in the 2011 and 2012 revenue requirement approved in EB-2010-0002.

ii) Please describe Hydro One's intention for recovery of amounts in the Impact for US GAAP Account; specifically, how and when are the amounts proposed to be recovered?

Response

i) Hydro One confirms that entries have been made to this account through to June 30, 2011. The entries made were consistent with the Board decision of EB-2010-0002 for Transmission rates and the APH October 2009 FAQ direction.

The June 30, 2011 balance in the Transmission IFRS – Incremental Transition Costs Account is a debit balance of $256,392 (inclusive of interest improvement at the Board's prescribed rate).

The amount of IFRS Transition Costs that were embedded in the 2011 and 2012 revenue requirement approved in EB 2010-0002 were $210,420 and $NIL for 2011 and 2012, respectively.

ii) Hydro One would propose to recover the amounts in the Impact for US GAAP account in the next Transmission cost of service proceeding following the availability of either 2012 or 2013 audited financial statements.

Ontario Energy Board (Board Staff) INTERROGATORY #21 List 1

Interrogatory

Ref: Exhibit D1/Tab1/Sch1/p.3 Impact for US GAAP Account

i) Please describe the differences between CGAAP and US GAAP referred to in this section and provide an estimate of the debits and credits that Hydro One anticipates will be recorded in this account.

ii) Please confirm that no other deferral and variance accounts are affected by the change to US GAAP from MIFRS.

iii) Has Hydro One identified any impact relating to the transition to US GAAP on balances embedded in revenue requirements or deferral/variance account balances approved in EB-2010-0002 or prior decisions specifically relating to employee future benefits and financial instruments?

Response

i) Hydro One has not yet identified any significant differences that would be recorded in this account. The account is to accommodate the impact of any CGAAP versus US GAAP differences identified at a later date that impact Hydro One Transmission's 2012 revenue requirement.

ii) The change does have an impact on the IFRS Incremental Transition Costs Account as described in Exhibit D1/Tab1/Sch1/p.2. No other accounts are impacted.

iii) No

<u>Ontario Energy Board (Board Staff) INTERROGATORY #22 List 1</u>

<u>Interrogatory</u>

Ref: Exhibit D1/Tab1/Sch1 – Employee Future Benefits

The Board granted continuance of the Pension Cost Differential Account in the EB-2010-0002 Hydro One Transmission Decision.

Page 59 of Hydro One Inc.'s December 31, 2010 audited financial statements, states:

> The pension cost variance account was established for Hydro One Networks' Transmission and Distribution Businesses to track the difference between the actual pension costs incurred by the Company and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension costs paid compared to OEB-approved amounts.

Page 60 of Hydro One Inc.'s December 31, 2010 audited financial statements states:

> *Deferred Pension*
> In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid into the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate-regulated accounting, operating, maintenance and administration expense would have been lower by $22 million (2009 - higher by $9 million).

> The balance in Hydro One Inc.'s December 31, 2010 audited financial statements for Hydro One's Deferred Pension Asset was $460 million debit and the balance in the Deferred Pension Regulatory Liability was $460 million credit.

As per Hydro One Inc.'s December 31, 2010 audited financial statements, a portion of page 67 is reproduced below:

	Pension 2010	Pension 2009	Employee Future Benefits other than Pension 2010	Employee Future Benefits other than Pension 2009
Funded status				
Unfunded benefit obligation	(297)	(230)	(1,178)	(1,004)
Unamortized net actuarial losses (gains)	746	640	144	10
Unamortized past service costs	11	14	11	14
Deferred pension asset (accrued benefit liability)	460	424	(1,023)	(980)
Less: Current portion	-	-	43	40
Deferred pension asset (long-term liability)	460	424	(980)	(940

i) Please file a copy of Hydro One Inc.'s December 31, 2010 audited financial statements.

ii) Please confirm that Hydro One as at December 31, 2010 records pension costs using the cash basis and records employee future benefits other than pension using the accrual basis. If this is not the case, please explain.

iii) Please confirm that under both IFRS and US GAAP Hydro One would cease to be able to use the cash basis to record pension costs, and must change to the accrual basis. If this is not the case, please explain. If Hydro One must make this change, please provide estimated dollar impacts for:

- the impact of this change on the 2012 revenue requirement approved in EB-2010-0002;
- how this impact is reflected in the proposed 2012 revenue requirement in this application; and
- the impact on balances in any deferral/variance account.

iv) Is Hydro One seeking to continue the Pension Cost Differential Account?

v) Deferred Pension Asset

Board staff notes that the Deferred Pension Asset, as described on page 67 of Hydro One Inc.'s December 31, 2010 audited financial statements, had a balance of $460 million debit as at December 31, 2010. Included in this amount was $746 million debit of unamortized net actuarial losses.

Board staff further notes that an additional amount of unamortized net actuarial losses of $144 million relating to employee future benefits other than pension was recorded in Hydro One Inc.'s December 31, 2010 audited financial statements.

a) Does Hydro One intend to put part of the balance of the Deferred Pension Asset (or any of its components), as described on page 67 of Hydro One Inc.'s December 31, 2010 audited financial statements, into the Pension Cost Differential Account?

Please note that this question relates to the balance of the Deferred Pension Asset that existed as at December 31, 2010 of $460 million, or any amount that existed prior to, or exists beyond December 31, 2010.
Please explain and provide the proposed amounts.

b) Are any of these amounts proposed to be put in the requested Impact for US GAAP Account? Please explain and provide the proposed amounts.

c) Did Hydro One incorporate any part of the balance or an estimate of the Deferred Pension Asset (or any of its components) as described on page 67 of Hydro One Inc.'s December 31, 2010 audited financial statements, into the 2012 revenue requirement approved in EB-2010-0002?

Please note that this question relates to the balance of the Deferred Pension Asset that that existed as at December 31, 2010 of $460 million, or any amount that existed prior to, or exists beyond December 31, 2010. Please explain and provide the amounts.

d) Did Hydro One incorporate any part of the balance of the Deferred Pension Asset (or any of its components) as described on page 67 of Hydro One Inc.'s December 31, 2010 audited financial statements, into the proposed 2012 revenue requirement in this application?

Please note that this question relates to the balance of the Deferred Pension Asset that that existed as at December 31, 2010 of $460 million, or any amount that existed prior to, or exists beyond December 31, 2010.

Please explain and provide the proposed amounts. Please differentiate between any amounts that were previously incorporated into the 2012 revenue requirement approved in EB-2010-0002, and any new amounts incorporated into the proposed 2012 revenue requirement.

e) e) If any of the amounts described in the Deferred Pension Asset questions above are not incorporated into the proposed 2012 revenue requirement, does Hydro One propose to recover these amounts? If so, when and how is Hydro One proposing to recover the amounts?

<u>Response</u>

i) Hydro One Inc.'s December 31, 2010 audited financial statements are provided as Attachment 1 to this schedule.

ii) So confirmed.

iii) Under IFRS, Hydro One confirms that it would cease to be able to use the cash basis to record pension costs in its financial statements and would change to the accrual basis. However, under US GAAP, Hydro One Networks' Distribution and Transmission businesses would still report pension costs on a cash basis externally using rate regulated accounting, consistent with the Board's approval to use a cash basis for rate setting.

iv) Yes.

v) Deferred Pension Asset

a) No. The Deferred Pension Asset does not meet the approved scope of the Pension Cost Differential Account. Further, it only exists at the Hydro One Inc. consolidated reporting level and is not included in Hydro One Networks Distribution's and Hydro One Networks Transmission's financial statements.

b) No.

c) No. See a) above.

d) No. See a) above.

e) No. Both Hydro One Networks' Distribution and Transmission businesses recover their pension costs on a cash basis.

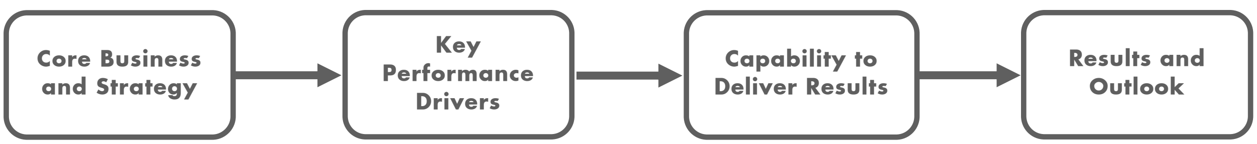
HYDRO ONE INC.
ANNUAL CONSOLIDATED FINANCIAL STATEMENTS

We prepare our financial statements in Canadian dollars in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2010 and 2009.

EXECUTIVE SUMMARY

We are wholly owned by the Province of Ontario (the Province), and our Transmission and Distribution Businesses are regulated by the Ontario Energy Board (OEB). Our mission and vision have been refined to recognize the unique role we play in the economy of the province and as a provider of critical infrastructure to all our customers. We will be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. We operate as a commercial enterprise with an independent Board of Directors. Our strategic plan is driven by our values: health and safety, stewardship, excellence and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial and transparent and values our customers. We strive for excellence by being trained, prepared and equipped to deliver high-quality service. We value innovation because it allows us to increase our productivity and develop enhanced methods to meet the needs of our customers. In 2010, we continued to focus on our core businesses, substantially maintained and improved our performance in various key areas of the Company, and made important contributions to the rebuilding of Ontario’s core infrastructure while preparing to meet the requirements of the Green Energy Act (GEA).

We manage our business using the following governance structure:



Core Business and Strategy

Our corporate strategy is based on our mission and vision and our values. Our strategic goals, which are discussed on page 4, encompass the core values that drive our business. Our strategy touches every part of our core business: health and safety; our customers; innovation; the reliability and efficiency of our systems; the environment; our workforce; shareholder value; and productivity.

Key Performance Drivers

We have identified performance drivers critical to achieving our strategic goals. Each driver is specific to measuring our success in achieving a specific goal. We establish specific performance targets against each driver every year aimed at achieving our strategic goals over time. For example, we calculate lost-time injury frequencies and medical attentions to measure our progress toward an injury-free workplace and the duration and frequency of unplanned interruptions to measure the success of our initiatives to increase the reliability of our transmission and distribution systems. Reduced carbon emissions demonstrate our commitment to protecting the environment. These and other key performance drivers are included in our discussion of our performance measures beginning on page 5.

Capability to Deliver Results

We continued to use a balanced scorecard approach and set 18 stretch targets for 2010 as we strive to manage our key performance drivers and deliver results each and every year. This year we met or exceeded 14 of 18 targets, representing an improvement over last year when we met or exceeded 8 of 13 stretch targets. We are on target to enable clean and renewable energy in Ontario with the implementation of our Bruce to Milton Project that will create Ontario’s new clean energy corridor. We continue to prioritize safety in the workplace, adding a new performance measure this year. We exceeded our target for lost-time injuries by 78% and exceeded our new target for medical attentions by 22%. We are focused on balancing customer needs in the changing electricity sector and achieved an overall satisfaction score of 89% for both our transmission and distribution customers. The results of our efforts are fully discussed in the section Performance Measures and Targets, beginning on page 5. Our capability to deliver results in each of our strategic areas is limited by risks inherent in the regulatory environment, our business, our workforce and the economic environment. These risks, as well as our strategies to mitigate them, are discussed beginning on page 25.

Results and Outlook

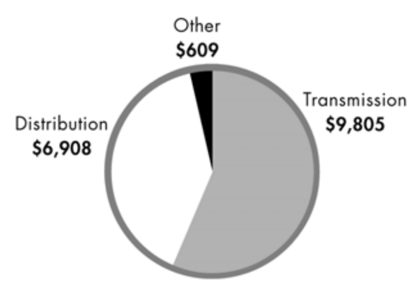
During 2010, our financial fundamentals remained strong, with current year net income of $591 million. Our OEB-approved revenue requirements for our Transmission and Distribution Businesses for 2010 were $1,257 million and $1,146 million, respectively. The approved rates support our work programs required to sustain our critical infrastructure and invest in a sustainable electricity system that supports renewable and cleaner generation. We maintained "A" category credit ratings and successfully issued $1,500 million in debt financing, while repaying $600 million of debt maturing in the year. A full discussion of our results of operations and financing activities can be found beginning on pages 14 and 18, respectively.

In 2010, we invested more than $1.5 billion in capital expenditures to improve system reliability and performance, address an aging power system, facilitate new generation and improve service to customers. Our estimated future capital expenditures for 2011 and 2012 have decreased marginally from those previously disclosed as a result of various letters received from the Minister of Energy, the introduction of a Long-Term Energy Plan (LTEP) and an OEB policy to further competition for transmission development. Similarly, we eliminated requirements for Green Transmission projects for new lines from our budgeted expenditures and refined our requirements to support distributed generation. The impacts were partially offset by requirements associated with our existing grid. We continue to focus on addressing aging infrastructure, including critical stations that serve industry and major customer load areas. Our future capital expenditures are more fully discussed beginning on page 21.

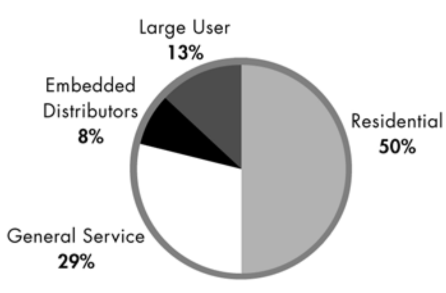
OVERVIEW

Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our Company. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre. Our system operates over relatively long distances and links major sources of generation to transmission stations and larger area load centres. In 2010, we earned total transmission revenues of $1,307 million primarily by transmitting approximately 142 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,600 MW and exports of approximately 6,000 MW of electricity. In terms of assets, our Transmission Business is our largest business segment, representing approximately 57% of our total assets.



Total Assets
December 31, 2010
(CAD $ millions)



2010 Distribution Revenues

Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province. We serve approximately 1.3 million rural and urban customers, local distribution companies (LDCs) connected to the distribution system, and 412 large user customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. We earned total distribution revenues in 2010 of $3,754 million. As illustrated in the accompanying chart, about half of our distribution revenues are earned from our residential customers. In terms of assets, our Distribution Business represents approximately 40% of our total assets.

Other

Our other business segment contributed revenues of $63 million in 2010 and has assets of about $609 million, which constitute 3% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc. (Hydro One Telecom), which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements, including a dedicated optical network providing secure, high-capacity connectivity across numerous health care locations in Ontario.

Our Strategy

Our corporate strategy is based on our mission and vision and our values. Our mission and vision is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs:

Health and safety: Nothing is more important than the health and safety of our employees and those who work on our property, as well as maintaining a safe environment for the public.

Excellence: We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality service.

Stewardship: We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.

Innovation: We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

We have eight strategic objectives that do not stand alone and are inextricably linked with one another. They drive the fulfillment of our mission and vision.

Creating an injury-free workplace and maintaining public safety. Health and safety must be integrated into all that we do. We must continue to create a passion for preventing injury. We will strengthen our already strong safety culture through our Journey to Zero initiative and achieve world-class results. We will continue to reinforce that nothing is more important than the health and safety of our employees.

Satisfying our customers. We will meet our commitments, make customers our focus in our planning, communicate effectively, coordinate across lines of business, and maximize opportunities to improve our corporate image.

Continuous innovation. Innovation is critical to achieving our mission and vision and represents one of our core values. Over the next two decades, we will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers with more capability to manage their power costs.

Building and maintaining reliable, cost-effective power delivery systems. Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on incorporating smart grid technology, providing reliable service over a diverse geography, supporting the connection of renewable generation, seeking efficiencies through productivity initiatives and remaining open to opportunities to rationalize the distribution sector.

Protecting and sustaining the environment. Consistent with our value of stewardship, Hydro One plays a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use.

Employee engagement. We believe our primary strength is the capability of our people. In order to sustain this advantage, we must address the issues of labour demographics, diversity, development of critical core competencies, and skill and knowledge retention. Our labour strategy will enable us to make significant gains in the areas of labour flexibility, productivity improvement and cost reduction.

Maintenance of a commercial culture that increases value for our shareholder. We are committed to keeping rates as low as possible for our customers, and delivering income and dividends to our shareholder. This is possible through our focus on reducing costs, managing our assets effectively and increasing productivity.

Productivity improvement and cost-effectiveness. To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our shareholder.

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

Performance Measures and Targets

We measure and target our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we achieve our strategic objectives**.** In 2010, we met or exceeded 14 of 18 stretch targets. Overall, we are making progress towards achieving our strategic goals.

Creating an injury-free workplace and maintaining public safety

The potentially hazardous nature of our business requires a continuous focus on safety. Our people underpin everything we do, and as a result, safety is paramount. Our efforts to achieve an injury-free workplace are measured by our lost-time injury frequency and our newly added reportable medical attentions frequency. Overall, we exceeded our challenging 2010 target of 0.23 lost-time injuries per 200,000 hours worked, which is also a considerable improvement over our 2009 results. We also exceeded our 2010 target of 3.6 medical attentions per 200,000 hours worked. Medical attentions are incidents reported to the Workplace Safety and Insurance Board that are more serious than basic first aid. While we monitor both of these measures to identify possible situations that may increase the risk of injury, medical attentions are considered a leading indicator. These injuries range from physical strains to those caused by electrical contacts. We continuously emphasize the improvement of safety performance and strive to achieve zero lost-time injuries by ensuring that all staff are appropriately trained and equipped for the hazards they may face. This involves continued coaching and mentoring, and building on our learning and experience.

At the end of 2009, we launched our Journey to Zero initiative aimed at identifying key opportunities for improvement in our health and safety system in order to achieve world-class health and safety performance. During 2010 we formed a steering committee for this initiative, held workshops to prioritize the opportunities identified at the end of last year and developed an action plan to address the top areas for improvement. In October 2010, we were pleased to be informed by the Workplace Safety and Insurance Board that we had passed our Workwell audit, a comprehensive independent review of all aspects of our workplace health and safety program including policies, standards, training, records, performance and employee representation.

We continue to promote public safety and the safe use of electricity through public service announcements and education programs in schools to teach children how to stay safe. We also continue to work with law enforcement agencies to combat copper theft, which endangers our employees and the public.

Satisfying our customers

Customer satisfaction is vital to our success. This is measured by a combination of independent surveys and transactional measures conducted for each of our customer segments. In 2010, the overall satisfaction level for both our distribution and transmission customers exceeded our targets. For our Distribution Business, overall customer satisfaction survey results of 89% exceeded our target of 81%. While we achieved consistent results compared to the prior year within our large distribution customer and residential and small business customer segments, we significantly increased customer satisfaction among distribution-connected generators. Satisfaction in this group was impacted by addressing concerns from last year's surveys, clarifying processes and enhancing communications with customers. Connection application volumes are increasing and we remain focused on managing customer expectations.

For our transmission customers, we experienced slightly lower results for our LDC customers than planned and are assessing the results to improve processes next year. However, our overall transmission customer survey results were offset by a significant improvement in our transmission-connected generator customer satisfaction as a result of addressing concerns noted in last year's surveys. We continue to strive for customer service excellence. We continue to make our customers a high priority, and implement targeted strategies designed to meet the unique needs of each customer segment and address their concerns through a range of initiatives to improve customer satisfaction levels.

Continuous innovation

We are committed to identifying and providing innovative solutions that will improve the reliability and efficiency of electricity delivery and provide our customers with more capability to manage their power consumption. Among our continuous innovation initiatives in 2010, smart meters remained a priority. We have more than 1,314,000 smart meters installed to date, of which approximately 1,140,000 meters are enabled to support time-of-use billing. This represents a significant step forward in supporting the Smart Grid initiative. We fell short of our target of 1,170,000 meters enabled to support time-of-use billing due to challenges encountered related to the communications network needed to address the diverse needs of the geography across the province. We continue to anticipate that our OEB commitments will be met in 2011.

A new measure for continuous innovation this year monitors green grid initiatives, which are an integral part of the GEA. These initiatives include establishing a communications network in the Greater Owen Sound area to test business applications for a smart electricity grid, developing a business case for further deployment of the communications network to the province, and developing utility solutions for the current challenges around installing and operating large numbers of distributed generation on our distribution system. We successfully achieved all 12 milestones related to these initiatives.

Building and maintaining reliable, cost-effective power delivery systems

As stewards of the province's electricity grid, we aim to maintain and build trust in our operations. In 2010, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for our customers in a safe, reliable and efficient fashion. In addition, our aim is to meet the growing demand for renewable generation. The reliability of our transmission and distribution systems is measured by the duration of unplanned customer interruptions throughout the year and our transmission system is further measured by the frequency of unplanned customer interruptions. In 2010, our transmission system met our reliability targets for both frequency and duration of interruptions. The transmission frequency of customer unplanned interruptions met the target for the year. The transmission duration of unplanned customer interruptions was 9.1 minutes, significantly exceeding the target of 16.0 minutes, and significantly improved from 19.7 minutes in 2009.

Due to a number of challenges experienced in the last quarter of the year, the reliability of our distribution system was impacted in terms of duration of interruptions. Two severe winter storms affected the reliability of our distribution system. The duration of interruptions for our distribution customers was 7.1 hours, or 0.2 hours higher than target and 0.1 hours higher than last year. We are conscious that residential customers and businesses of all sizes require reliable service, and consequently, we will continue to strive to improve the reliability of both our transmission and distribution systems.

Protecting and sustaining the environment

As stewards of significant electricity assets, we have implemented a number of environmental initiatives aimed at instilling environmental awareness and action within our corporate culture. In 2010, we assessed two key metrics related to the Bruce to Milton Project and greenhouse gas reductions. We met our milestone targets related to the Bruce to Milton Project, which will create Ontario's new clean energy corridor. Successful completion of the Bruce to Milton Project will increase transmission capability to deliver 1,700 MW of renewable generation identified in the area, as well as about 1,500 MW of power from the refurbished units at the Bruce Power Facility. On December 16, 2009, we received conditional Environmental Assessment approval for the project. Preparation of this environmental assessment involved three years of technical and environmental field work, and extensive consultation with land owners, interest groups, elected officials and First Nations and Métis communities. This year, we were recognized by the CEA, receiving an Environmental Commitment Award for our extensive Biodiversity Initiative related to the Bruce to Milton Project. This initiative goes beyond our traditional approach to biodiversity, using innovative ways of mitigating the effects of woodlot clearing. Our Biodiversity Initiative will develop and support a number of stewardship and biodiversity opportunities such as replanting grasslands, removal of invasive species and restoring forests in the communities affected by the Bruce to Milton Project. We are funding 23 locally-designed biodiversity projects located on public lands within the four watersheds the Bruce to Milton Project crosses. These projects will help to ensure environmental sustainability and will maintain and enhance the natural habitat. This initiative is being undertaken in collaboration with First Nations and Métis communities and community-based stakeholders and agencies.

We take our responsibility to reduce our carbon footprint very seriously. We did not meet our overall greenhouse gas reduction target as a result of not being able to verify our specific target to reduce sulphur hexafluoride emissions. However, we did exceed the target for the reduction of greenhouse gas emissions from other programs. In 2010, we removed approximately 2,595 metric tonnes of greenhouse gases from the environment, exceeding our target of 1,250 metric tonnes from these other initiatives that were aimed at improved deliveries of bio-diesel fuel at Hydro One Remotes, better efficiency of fleet utilization, including our Tire Smart Program, the purchase of fuel-efficient and hybrid vehicles and green initiatives at our facilities. Our continued commitment to the people of Ontario has been recognized again this year by Corporate Knights Inc., an independent company focused on promoting and reinforcing sustainable development in Canada. We were named one of the top five Corporate Citizens in Canada, our third top-ten ranking in three years.

We have a publicly available environmental policy and are committed to protecting the environment for current and future generations. Adhering to this policy, we have many initiatives within our Company aimed at fulfilling our commitment to protect the environment, some of which are linked to a specific performance measure. All of our environmental initiatives are part of an internal program called Greener Choices. Greener Choices was created to help our Company become more energy-efficient and to reduce the emissions and environmental impacts of our fleet and our facilities. Our initiatives fall under four categories: helping our employees to be more aware of what they can do to reduce their environmental impacts; creating a culture of conservation within our Company; making our facilities more energy-efficient; and reducing the emissions of our fleet of vehicles.

Skill development and knowledge retention

Given the retirement profile of our employees, we are in a period of significant demographic change. This change is taking place across the electricity sector and we have taken a leadership role to address the transition. We have embarked on an aggressive workforce renewal program that will lead to a diverse, fully engaged workforce. In addition to our partnership with four community colleges, we strengthened our association with various Canadian universities as part of a comprehensive strategy to meet our staffing needs well into the future. We also helped to establish the Ryerson University Centre for Urban Energy (the Centre). Our goal to attract and retain future sector leaders involves demonstrating that Hydro One is an employer of choice. In addition, we aim to facilitate retention and mentoring by focusing on employee engagement. We measure employee engagement across all lines of business using a confidential employee engagement survey. The grand mean score in 2010 was 3.70 out of 5, an improvement from the 2009 score of 3.63, but slightly lower than the 2010 target of 3.73. Detailed results of the 2010 survey will be used to actively address lower-performance areas and effectively implement targeted strategies designed to increase engagement levels.

Maintenance of a commercial culture that increases value for our shareholder

In 2010, we continued our commitment to maintain strong financial fundamentals. Our targets included net income and our credit ratings, which were both achieved. Net income for the year exceeded target mainly as a result of the higher temperatures experienced during the summer combined with effective cost management. A discussion of our financial results can be found on page 14 and of our liquidity and capital resources on page 18.

Our financial performance and the business environment in which we operate are taken into consideration in setting both our short-term and long-term credit ratings. During 2010, our long-term and short-term debt credit ratings remained unchanged. Credit ratings are provided by DBRS Limited, Moody's Investors Service Inc. and Standard

& Poor's Rating Services Inc. (S&P). Maintaining credit ratings in the "A" category allows us to continue to access the long-term debt markets. We have been able to successfully secure sufficient and cost-effective debt financing. Our current credit ratings facilitate ongoing access to debt markets at a reasonable cost to fund the infrastructure requirements of our system.

Productivity improvement and cost-effectiveness

In 2010, we remained focused on workplace productivity and its contribution as an enabler of our work programs. For our Transmission Business, productivity is measured using the cost per asset value, which is calculated as capital and maintenance program expenditures as a percentage of transmission assets. For our Distribution Business, the calculation is normalized for line length due to the rural nature of our service territory. The targets for both measures were to achieve top-quartile results when benchmarked against comparable North American utilities. Transmission and distribution productivity results for the year were both on target.

Two additional corporate measures were implemented this year. The Collaborative Planning Index measures the effectiveness of workflow between key lines of business as a result of improved integration and teamwork. The other new measure assesses the savings derived from our entity-wide information system replacement and improvement project, placed in service in 2009. In 2010, we slightly exceeded our Collaborative Planning Index target of 85%, a measure based on the average of three metrics related to the release of work, planning and order filling. We have also exceeded our target savings of $28 million related to the entity-wide information system replacement and improvement project, with actual savings of approximately $34 million. We will continue to build on the success of our new entity-wide information system to increase the cost effectiveness of work program planning, processing and execution to achieve reductions in our labour unit costs.

REGULATION

Our electricity Transmission and Distribution Businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our Distribution Business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Electricity Rates

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the Ontario Power Authority (OPA). Prices are reviewed every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period. Effective May 1, 2010, we started migrating our customers to time-of-use (TOU) rates and have a plan in place to transition the majority of our RPP customers to TOU rates in 2011. On September 16, 2010, we filed an application with the OEB for an exemption from mandated time-of-use pricing, affecting approximately 150,000 customers located in very rural and sparsely populated portions of our service territory that are currently out of reach of our smart meter telecommunications infrastructure. In early 2011, the OEB approved our request for an extension until the end of 2012.

As announced in its 2010 fall economic update, the Province introduced the *Ontario Clean Energy Benefit Act, 2010*, which is designed to assist Ontario electricity consumers through the transition to a cleaner electricity system. Under this Act, eligible residential, farm and small business consumers receive financial assistance in the amount of a 10% credit with respect to the total cost of electricity on their bills, including tax. This assistance is being provided to eligible customers for a five-year period, beginning January 1, 2011. In January 2011, our Company issued its first bills to customers with this credit applied to their electricity costs.

Customers that are not eligible for the RPP and wholesale customers pay the market price for electricity, adjusted for the difference between market prices and prices paid to generators under the *Electricity Act, 1998*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market as well as ensuring the reliability of the integrated power system.

Green Energy Act and Long-Term Energy Plan

In addition to the oversight role of the OEB, and the market-monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and assist with the stability of rates for RPP customers, among other roles. As part of its mandate, and consistent with the Province's direction regarding supply mix, the OPA developed the Integrated Power System Plan (IPSP), which was submitted for OEB review and approval in August 2007. On September 17, 2008, the Province directed the OPA to review a portion of its proposed IPSP focusing on renewable energy and conservation as well as to undertake an enhanced process of consultation with First Nations and Métis communities. As a result of the Minister of Energy and Infrastructure's directive, the OEB adjourned its review of the IPSP on October 2, 2008.

On May 14, 2009, the GEA was passed in the Ontario Legislature. On September 21, 2009, to support the GEA and help bring renewable energy to the grid our Company received a letter from the then Minister of Energy and Infrastructure requesting us to immediately proceed with the planning and implementation of 20 major transmission projects. On May 7, 2010, the Minister of Energy and Infrastructure requested our Company to focus on those items that are essential to the safe and reliable operation of our existing assets or projects already under development and approved by the OEB, or are critical to the connection of renewable generation projects that have been identified by the OPA as part of the government's green energy agenda. As a result, we decided to suspend our work on the 20 major transmission projects. On August 26, 2010, the OEB released its new policy on the Framework for Transmission Project Development Plans. This policy sets out a framework for new transmission investment in Ontario by introducing competition for transmission development through an open bid process.

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

The OPA continues to procure new, cleaner and renewable generation in Ontario. On October 1, 2009, the OPA launched the Feed-In-Tariff (FIT) Program in accordance with the directive issued by the Minister of Energy and Infrastructure to the OPA. The program is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy and waterpower up to 50 MW.

On November 23, 2010, the Ministry of Energy released Ontario's LTEP which sets out the Province's expected electricity needs until 2030 and supports the continued procurement of new, cleaner generation. The LTEP addresses seven key areas: demand, supply, conservation, transmission, Aboriginal communities, capital investments and electricity prices. In conjunction with the release of its LTEP, the Province released a draft Supply Mix Directive for consultation. The draft Supply Mix Directive outlines the goals to be achieved through a new detailed long-term plan and directs the OPA to prepare an IPSP to meet those goals, as set out in the LTEP. The comment period for the draft Supply Mix Directive expired on January 7, 2011. It is anticipated that a Supply Mix Directive will be formally issued to the OPA and will form the basis for a new IPSP. The OPA is anticipated to release an updated IPSP to the OEB in 2011 for its review and approval.

The draft Supply Mix Directive to the OPA identifies five priority transmission projects over seven years. On December 22, 2010, we received a letter from the Minister of Energy updating the September 21, 2009 letter from the Minister of Energy and Infrastructure, and requesting us to immediately proceed with the necessary planning and development work to advance three of the projects in an expedited timeframe, in combined consultation with the OPA and IESO. In addition, we were asked to develop a plan to prioritize the cost-effective upgrades to our systems to safely and reliably accommodate additional renewable energy for small generation projects (see Future Capital Expenditures).

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

Transmission and Distribution System Codes

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

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

On June 30, 2010, Hydro One Networks Inc. (Hydro One Networks), in respect of our Distribution Business, filed an application with the OEB requesting an exemption from certain cost responsibility rules contained in the DSC for distributed generation projects under the Renewable Energy Standard Offer Program (RESOP). The application sought to deal with unanticipated costs that arose as a result of the connection of certain renewable generation facilities for generators. These generators applied to connect to our system prior to amendments made to the code on October 21, 2009. Under the rules in force at the time, all costs of connection were assigned to generators and we requested an exemption from those rules to allow for recovery of the unforeseen expenditures from ratepayers. On December 20, 2010, the OEB released its decision approving deferral accounts to capture the expenditures to be brought forward for review and approval at the next cost-of-service application.

Conservation and Demand Management

In 2009, the OPA continued to be responsible for coordinating the delivery and funding of conservation and demand management (CDM) programs. This coordination furthered initiatives undertaken by individual LDCs, including the distribution businesses of our subsidiaries Hydro One Networks and Hydro One Brampton Networks Inc. (Hydro One Brampton), as a result of OEB program requirements associated with the third phase Market Adjusted Rate of Return (MARR). Our CDM programs funded through the OPA in 2010 amounted to approximately $31 million, compared to $16 million in 2009. The *Ontario Energy Board Act*, *1998*, as amended by the GEA, provides direction to the OEB to take steps to establish CDM targets to be met by LDCs and other licensees. The Minister of Energy and Infrastructure's March 31, 2010 directive set a province-wide LDC CDM target for Ontario's LDCs. The two key CDM targets for LDCs over the four-year period beginning January 1, 2011 are to reduce 1,330 MW of provincial summer peak demand and 6,000 GWh of cumulative energy savings, collectively.

On June 22, 2010, the OEB provided notice under the *Ontario Energy Board Act, 1998* of the creation of a proposed CDM Code for electricity distributors. The new code proposes specific CDM targets for all LDCs as directed by the Minister of Energy and Infrastructure earlier this year. The proposed allocation of the overall targets to our Company are a 256 MW reduction of provincial peak demand and a 1,208 GWh reduction of electricity consumption, representing, respectively, 19.2% and 20.1% of the total target savings established for all LDCs. The CDM Code also set out the conditions and rules that LDCs are required to follow if they choose to use OEB-approved CDM programs to meet their CDM targets. On November 1, 2010, Hydro One Networks' Distribution Business filed its CDM strategy and CDM Program application with the OEB in accordance with the requirements of the CDM Code. An oral hearing for the review and approval of our CDM application and funding of our CDM programs has been scheduled to start in March 2011.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of smart meters in all homes and small businesses in Ontario by December 31, 2010. These meters are expected to be capable of measuring and reporting usage over predetermined periods, being read remotely, and, when combined with communications systems, will be capable of providing customers with access to information about their consumption. In 2007, the Province appointed the IESO as the interim smart meter entity that will oversee the collection and management of data. LDCs, including our distribution businesses, are accountable for the deployment of smart meter infrastructure and related technology for communications to meet minimum requirements as defined in regulations, as well as the implementation of time-of-use rates. In 2010, we continued our focus on building an advanced distribution solution and launched our smart grid initiative to leverage the infrastructure from our smart meter investment which is required to connect and manage large volumes of distributed generation on our distribution system (see Future Capital Expenditures).

Renewed Regulatory Framework

On October 27, 2010, the OEB announced its plan to develop a renewed regulatory framework for electricity given the significant role network investment will have in the electricity sector in the future. The renewed regulatory framework will be developed through three policy initiatives. First, the OEB will re-examine its approach to network investment planning by transmitters and distributors, including considering ways to encourage distributors and transmitters to plan their investments with the total bill impact in mind. Second, it will review its rate mitigation policy by examining alternative approaches and rate treatments that might smooth the impact of rate or bill increases on consumers. Third, it will review its current rate-making policies to ensure that they continue to facilitate the cost-effective and efficient implementation of OEB-approved plans.

Transmission Rates

Hydro One Networks

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

On August 16, 2007, the OEB issued its decision in respect of our 2007 and 2008 transmission rate application. As part of that decision the OEB approved the disposition of export and wheeling fees liability and the transmission market-ready regulatory asset, which was factored into rates and refunded to customers over the four-year period ending December 31, 2010.

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

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

2% and 9% for 2009 and 2010, respectively, representing a less than 1% increase on an average customer's total bill in each year.

On December 11, 2009, the OEB issued its final report on the cost-of-capital review, which concluded that the formula-based return on equity (ROE) needed to be reset and refined. On January 5, 2010, we filed a motion with the OEB to review aspects of its decision on our 2010 transmission rates, including an increase of the ROE used in calculating the 2010 revenue requirement to 9.75% from 8.39%, based on the new OEB-approved formula. On April 5, 2010, the OEB issued its decision, denying Hydro One Network's motion to vary the ROE used to calculate the revenue requirement for 2010 transmission rates. As a result of the decision, the 2010 revenue requirement remained at $1,257 million on the basis of an ROE of 8.39%.

On May 19, 2010 we submitted an application for 2011 and 2012 transmission rates in continued support of our aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the GEA. This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012, which represents an estimated increase in rates of 15.7% and 9.8%, respectively, or 1.2% and 0.7% on an average customer's monthly bill. The application was filed using the new OEB-approved formula for ROE and took into consideration the OEB staff report on the regulatory treatment of infrastructure investment in connection with rate-regulated activities (RRA) of Ontario distributors and transmitters, issued in January 2009.

On December 23, 2010, the OEB issued its decision effective January 1, 2011, which resulted in a revenue requirement of $1,346 million for 2011 and $1,658 million for 2012, reflecting transmission rate changes of approximately 7% in 2011 and 26% in 2012. The 2011 revenue requirement was lower than requested primarily due to a lower prescribed ROE resulting from a lower forecasted cost of debt, the denial of our request to recover the cost of capital of the construction work-in-progress for Bruce to Milton and an operation, maintenance and administration envelope reduction. Our 2012 revenue requirement was also impacted by the above noted factors, but was higher than originally submitted due to the OEB directing our Company to adopt IFRS accounting for indirect overheads capitalized, resulting in approximately a $200 million increase in 2012. Our Company was required to establish a variance account to capture any difference in the revenue requirement impact attributed to adopting IFRS capitalization accounting in 2012.

On January 17, 2011, the Power Workers Union submitted an appeal of the decision to the Ontario Superior Court of Justice (Divisional Court) asserting that the OEB failed to permit our Company to recover proposed prudently incurred operation, maintenance and administration costs and therefore, that a legal error was made. The appeal is not anticipated to affect the collection of the new 2011 transmission rates during the proceeding.

Distribution Rates

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

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

Hydro One Networks

On December 18, 2008, the OEB issued a decision approving substantially all of the work program expenditures submitted in our 2008 cost-of-service distribution rate application. The decision was effective May 1, 2008 with an implementation date of February 1, 2009, and approved the establishment of the Revenue Recovery Account or Rider 4 to record the revenue differential between existing distribution rates and new rates from May 1, 2008. The Rider 4 is being recovered over a 27-month period, commencing February 1, 2009 and ending April 30, 2011. As part of its decision, the OEB also approved certain excess functionality expenditures for smart meters and the continuance of the 93 cents per month per metered customer. In a past proceeding, the OEB approved for recovery our expenditures incurred related to minimum functionality for advanced metering infrastructure. As a result, the difference between revenue recorded on this basis and actual recoveries received under existing rate adders are reflected as the carrying value of the regulatory asset account.

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

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

Our application included the Green Energy Plan (GEP) for our Distribution Business, filed in response to the GEA, which directed the OEB to require transmitters and distributors to file plans that would lead to the expansion of their systems to facilitate renewable energy. Our plans identified the expansion and reinforcement of the distribution system required to accommodate the connection of renewable energy generation facilities and outlined the development and implementation of the smart grid in our distribution system. Our GEP reflected changes to the *Ontario Energy Board Act, 1998*, as amended by the GEA and stipulated in Ontario Regulation 330/09. The amendments provided a new mechanism for rate protection, whereby some or all of the OEB-approved costs incurred by a distributor to make an eligible investment for the purpose of connecting or enabling the connection of renewable energy generation to its distribution system may be recovered from all provincial ratepayers, rather than solely from ratepayers of the distributor making the investment.

On April 9, 2010, the OEB released its decision approving revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 to support the necessary work programs, the implementation of the GEA and the installation of smart meters. The 2010 and 2011 revenue requirements were lower than originally requested, reflecting reductions in operation, maintenance and administration expenses, capital expenditures and working capital requirements. As part of its decision, the OEB also approved certain distribution-related deferral account balances sought by our Company in our application, including retail settlement variance accounts, the remainder of a regulatory asset recovery account, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a single regulatory account (Rider 6) to be recovered over an 18-month period from May 1, 2010 to December 31, 2011. Further, the OEB requested the establishment of deferral accounts to track the difference between the revenue recorded on the basis of our GEP expenditures incurred and actual recoveries received under the approved funding adder or rider.

The 2010 distribution rates were implemented on May 1, 2010, reflecting a rate increase of approximately 9.3%, or approximately 3% on an average customer's total bill. Our 2011 revenue requirement was adjusted to reflect the OEB's decision to decrease OM&A by $40 million and was adjusted to reflect a $44 million capital program reduction. On November 15, 2010, the OEB issued its cost of capital parameter updates for rates effective January 1, 2011. The new ROE value for 2011 is 9.66%. Applying this lower ROE produces a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement results in an average distribution rate increase of approximately 8.7% for 2011, or 3.0% on an average customer's total bill.

Hydro One Brampton

On November 7, 2008, our subsidiary Hydro One Brampton filed an application for 2009 rates on the basis of the OEB's second-generation IRM policy, which incorporates an OEB-approved formula that considers inflation and efficiency targets. On March 13, 2009, the OEB released its decision and revised rates, including an amount of

$1.00 per month per metered customer for smart meters, were approved for implementation effective May 1, 2009. Overall, the impact on an average customer's total bill was marginal.

On November 6, 2009, an application for 2010 distribution rates was filed on the basis of the OEB's second-generation IRM process. On April 13, 2010, the OEB released its decision regarding this rate application approving our submission on the basis of the OEB's cost-of-capital and second-generation IRM policies. The revised rates were implemented on May 1, 2010 and resulted in a reduction of approximately 8.3%, or 2.2% on an average customer's total bill in the year.

On June 30, 2010, we submitted a 2011 cost-of-service application, which was subsequently adjusted on September 2, 2010 to reflect the Canadian Accounting Standards Board's decision to allow the deferral of the adoption of International Financial Reporting Standards (IFRS) implementation for rate-regulated entities to January 1, 2012. The updated submission was filed on November 8, 2010 and requested a revenue requirement of approximately $63 million. The oral hearing concluded on December 7, 2010 and we expect a decision in the first quarter of 2011.

Hydro One Remote Communities Inc.

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

On November 4, 2009, we filed an application for 2010 rates under the OEB's third-generation IRM, which sought approval of an increase to basic rates for the distribution and generation of electricity effective May 1, 2010. The increase reflected the standard inflationary adjustments incorporated in the third-generation IRM applications. On April 14, 2010, the OEB issued a decision regarding this rate application under the OEB's third-generation IRM policies. The revised rates were approved for implementation on May 1, 2010 and reflect an increase of approximately 0.4%, the overall impact of which on an average customer's total bill is marginal.

On October 15, 2010, an application for 2011 distribution rates was filed on the basis of the OEB's third-generation IRM seeking approval for an increase of approximately 0.4% to basic rates for the distribution and generation of electricity effective May 1, 2011. We expect to update our requested rate increase when the OEB issues its inflation and productivity factors for IRM filers in the first quarter of 2011.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**	**$ Change**	**% Change**
Transmission	1,307	1,147	160	14
Distribution	3,754	3,534	220	6
Other	63	63	-	-
	5,124	4,744	380	8
Average annual Ontario 60-minute peak demand *(MW)* [1]	21,572	20,798	774	4
Distribution – units distributed to customers *(TWh)*[1]	29.1	28.9	0.2	1

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

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenue associated with transmitting excess generation to surrounding markets and ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were higher by $160 million, or 14%, compared to 2009. The OEB rendered its decision on our 2009 and 2010 transmission rate application on May 28, 2009. The decision followed extensive oral and written reviews of our evidence submitted for the necessary funding in support of system requirements. The resulting tariff increases approved effective July 1, 2009 and January 1, 2010 support our in-service capital investments in respect of the Province's supply mix policy, including the phase-out of coal-fired generation and addressing aging infrastructure. These increases resulted in higher revenues of $119 million. We also experienced higher revenues of $12 million associated with certain OEB-approved deferral accounts as a result of the decision.

Also contributing to increased revenue was the higher average monthly peak demand experienced during the year. The average annual Ontario 60-minute peak demand and the overall related load were 774 MW and 9,282 MW higher than last year, respectively, resulting in higher revenues of $37 million. Weather was generally milder over the winter months and unseasonably hot during the summer months, compared to the prior year. Our system performed well under these extreme conditions.

Transmission tariff revenue increases were partially offset by lower ancillary revenues of approximately $8 million due to the impact of the May 28, 2009 OEB decision. Consistent with this decision, ancillary revenues received in excess of OEB-approved levels are recorded in a regulatory liability account and are not recognized as revenue.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $220 million, or 6%, compared to 2009, including an increase in the recovery of higher purchased power costs of $148 million, as described below in the section "Purchased Power."

Increases in revenue reflect two OEB decisions on the distribution tariff rates of our subsidiary, Hydro One Networks. On May 13, 2009, the OEB approved new tariff rates under the third-generation IRM effective May 1, 2009. On April 9, 2010, the OEB approved new tariff rates following our cost-of-service application effective May 1, 2010. Both decisions followed extensive written and oral reviews of the evidence we submitted for the maintenance and investment requirements of the distribution system, including those to support renewable distributed generation. The combined impact of these decisions was an $82 million increase. These tariff rate increases support the maintenance and investment requirements of our distribution system and enable the safe and reliable delivery of electricity to our customers throughout Ontario. We also experienced higher revenues of $7 million associated with certain OEB-approved deferral accounts for the year.

Distribution revenue increases were partially offset by lower energy consumption, resulting primarily from the milder weather in the first quarter of the year, partially offset by unseasonably hot weather during the summer months, which reduced our distribution revenues by $3 million compared to last year. In addition, revenues associated with the recovery of a distribution-related regulatory account ceased effective April 30, 2010, resulting in a revenue reduction of $16 million compared to last year.

We also experienced higher ancillary revenues of approximately $2 million compared to the prior year.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and comprise the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on time-of-use billing, both adjusted twice annually. The vast majority of RPP customers are anticipated to be on time-of-use billing by the end of June 2011. Customers that are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP for the reporting period is provided below.

Summary of RPP

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2008	1,000	750	5.6	6.5
May 1, 2009	600	750	5.7	6.6
November 1, 2009	1,000	750	5.8	6.7
May 1, 2010	600	750	6.5	7.5
November 1, 2010	1,000	750	6.4	7.4

RPP Time-of-Use	**Rates (cents/kWh)**		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
May 1, 2010	9.9	8.0	5.3
November 1, 2010	9.9	8.1	5.1

Purchased power costs increased in 2010 by $148 million, or 6%, to $2,474 million for the year compared to 2009. The increase in our purchased power costs was primarily due to the impact of changes in the OEB's RPP rate for residential and other eligible customers of $84 million, higher transmission charges of $33 million due to the OEB's transmission rate decisions effective July 1, 2009 and January 1, 2010, higher purchased power costs for customers that are not eligible for the RPP of $33 million and higher demand for electricity of $13 million. The effect of these increases was partially offset by lower wholesale market service charges levied by the IESO of $15 million.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**	**$ Change**	**% Change**
Transmission	416	438	(22)	(5)
Distribution	602	564	38	7
Other	60	55	5	9
	1,078	1,057	21	2

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $22 million, or 5%, in 2010 compared to last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. We substantially completed our work program requirements while focusing on productivity. Effective delivery of our maintenance program, particularly on power equipment, enabled us to reallocate resources to the timely delivery of our expanded capital programs. Given favourable weather conditions in the first half of the year, together with productivity improvements resulting from the implementation of our entity-wide information system, we were able to effectively execute our work programs. As a result, we experienced lower planned line maintenance expenditures, lower expenditures in our forestry programs and lower requirements for engineering support. Our expenditures in support of our transmission system have also decreased by $8 million, primarily reflecting the redirection of resources and the elimination of capital tax by the Canada Revenue Agency (CRA) effective July 1, 2010, partially offset by a one-time contribution of $27 million to the pension plan during the last quarter of this year.

Distribution

Operation, maintenance and administration expenditures required to maintain our low-voltage distribution system increased by $38 million, or 7%, compared to last year. Our work program expenditures increased by $11 million primarily as a result of favourable weather allowing us to deliver a larger forestry program in a cost-effective manner. Additionally, we experienced increased requirements within our customer care and engineering support programs, as well as within our smart meter program due to ongoing operational costs for installed meters. These expenditures were partially offset by lower expenditures within our lines maintenance program, including storm restoration, inspection and testing of pole transformers and field meter readings as installed smart meters begin to reach the required level of reliable communication. Our expenditures in support of our distribution system were higher by $27 million, reflecting a one-time contribution to the pension plan of $21 million during the last quarter of this year as well as the redirection of resources, partially offset by the elimination of capital tax by the CRA effective July 1, 2010.

Depreciation and Amortization

Depreciation and amortization expense reflect a net increase of $46 million, or 9%, to $583 million in 2010 compared to last year. This was mainly attributable to increased depreciation and amortization expense of $45 million from new assets coming into service, consistent with our ongoing capital work program. A further increase of $7 million was the result of increased fixed asset removals associated with our capital projects. Amortization of regulatory and other assets decreased by $6 million due to the completion of the amortization of a distribution regulatory account during the second quarter of this year, partially offset by increased amortization of our environmental regulatory asset related to higher expenditures necessary to comply with Environment Canada's regulations on the removal of polychlorinated biphenyls.

Financing Charges

Financing charges increased by $34 million, or 11%, to $342 million for 2010 compared to last year. Financing charges increased by $40 million mainly due to an increased average level of debt, partially offset by a lower average effective interest rate. Lower capitalized interest of $4 million also contributed to higher financing charges this year. Although we had higher levels of construction in progress, we capitalized less interest due to lower OEB-approved interest capitalization rates. These increases were partially offset by changes in interest income and other ancillary amounts which reduced overall financing charges by $10 million.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes (PILs) to the OEFC in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes, the liability method is used. The change in future taxes relating to both the unregulated and regulated businesses, in respect of temporary differences that are not considered for the rate-making process, results in a future tax provision that is charged to the income statement. The change in future taxes relating to temporary differences of the regulated business that are considered for the rate-making process results in a regulatory asset or regulatory liability.

The provision for payments in lieu of corporate income taxes increased by $10 million, or 22%, to $56 million compared to 2009. The increase was primarily due to higher pre-tax income in the year, partially offset by higher net temporary differences related to certain regulatory accounts and a reduction in the statutory rate from 33.0% to 31.0%.

Net Income

Net income of $591 million was higher by $121 million, or 26%, compared to 2009 results. Revenues were affected by the OEB-approved rate decisions that support investments in respect of supply mix policies, including the phase-out of coal-fired generation, necessary maintenance and investment requirements of our systems, and investments to address aging infrastructure. These investments in our transmission and distribution systems are reflected in the increase of approximately $1.1 billion in our fixed assets from the prior year. Revenues were also affected by a higher average monthly peak demand due to hotter than average weather during the summer months, partially offset by milder weather during the winter months. These impacts were partially offset by a one-time contribution to our pension plan, which was enabled by our effective cost management over operating costs in the year.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2009 through December 31, 2010. This information is derived from our unaudited interim Consolidated Financial Statements, which, in the opinion of management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include the normal recurring adjustments necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2010				2009			
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**
Total revenues[1]	1,280	1,360	1,165	1,319	1,207	1,144	1,090	1,303
Net income[1]	99	218	105	169	111	100	82	177
Net income to common shareholder[1]	94	214	100	165	106	96	77	173

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**
Operating activities	1,164	892
Financing activities		
Long-term debt issued	1,500	1,150
Long-term debt retired	(600)	(400)
Short-term notes payable	(55)	55
Dividends paid	(28)	(188)
Investing activities		
Capital expenditures	(1,570)	(1,566)
Long-term investments[1]	(250)	
Other financing and investing activities	37	15
Net change in cash and cash equivalents	198	(42)

[1] Represents $250 million of Province of Ontario Floating Rate Notes.

Operating Activities

Net cash from operating activities increased by $272 million to $1,164 million compared to last year. This increase primarily reflects higher net income and changes to accounts payable balances due to increases such as our purchased power costs related to the demand for electricity, timing of prepayments from customers and increased taxes payable related to the implementation of the HST. Changes in accounts receivable balances and in certain regulatory accounts also impacted net cash from operations.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holdings of Province of Ontario Floating Rate Notes.

At December 31, 2010, we had no short-term notes outstanding. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks and the holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program together with anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. During the second quarter, we increased the amount of our $500 million revolving credit facility, entered into in the first quarter, to $1,250 million and we extended the term of the facility to June 2013. Also in the second quarter, we cancelled the $750 million revolving credit facility which would have matured in August 2010.

At December 31, 2010, we had $7,775 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2011 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. On July 27, 2009, we filed a base shelf prospectus to renew our MTN Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program until August 2011 is $3,000 million, of which $1,250 million was remaining and available as at December 31, 2010.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations as of December 31, 2010.

In 2010, we successfully issued $1,500 million in cost-effective long-term debt under our MTN Program, consisting of $1,000 million in the first quarter and $500 million in the third quarter. We repaid $600 million in maturing long-term debt, including $400 million in the second quarter and $200 million in the fourth quarter. In 2009, we issued $1,150 million in long-term debt under our MTN Program and repaid $400 million in maturing long-term debt. During 2010, we reduced our short-term notes by $55 million, all in the first quarter. In 2009, we increased our short-term notes by $55 million.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations and maintaining the deemed regulatory capital structure. Financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations are also taken into consideration. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

In 2010, we paid dividends to the Province in the amount of $28 million, consisting of $10 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $170 million and preferred dividends of $18 million. In 2010, cash dividends per common share were $100 compared to $1,700 per common share in 2009. Cash dividends per preferred share were $1.375 in each of 2010 and 2009.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, we target to maintain an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**	**$ Change**	**% Change**
Transmission	936	918	18	2
Distribution	629	643	(14)	(2)
Other	5	5	-	-
	1,570	1,566	4	-

Transmission

Transmission capital expenditures increased by $18 million in 2010 to $936 million, compared to 2009. Expenditures to expand and reinforce our transmission system were $524 million, representing an increase of $7 million over last year. These expenditures primarily consist of those on inter-area network and local area supply development projects. We completed a number of multi-year projects and put them in service and other projects are beginning to progress. We continued to invest in a number of inter-area network upgrade projects to support the Province's supply mix objectives for generation. We also continued to make investments in our local area supply projects to address growing loads. These expenditures were partially offset by a reduction in expenditures associated with load customer connection projects as well as local area supply and inter-area network projects that were substantially completed this year.

Inter-area network upgrades with significant expenditures included the Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area, and the Northeast Transmission Reinforcement Project, which will increase the North-South interface transfer capability to access available northern generation. The Northeast Transmission Reinforcement Project is comprised of work to install static var compensators (SVCs) at Porcupine and Kirkland Lake Transformer Stations. In addition, we are installing SVCs at Nanticoke and Detweiler Transformer Stations, which in the short term will support increased generation from the Bruce Nuclear facility and in the longer term, will enhance the transfer capability between Southwestern Ontario and the Greater Toronto Area (GTA). The installation of SVCs represents new technology to our system and we successfully put one of them in service at the end of the year. These investments were partially offset by lower expenditures associated with the installation of capacitor banks in Southwestern Ontario, which is substantially complete. This equipment provides interim protection to the Bruce Nuclear facility and expands transmission capacity in Southwestern Ontario. In addition, we incurred lower expenditures associated with the Cherrywood Transformer Station to Claireville Transformer Station Connection Project, which will enable greater transfer capability across the GTA to accommodate power flows resulting from the new Hydro-Québec interconnection. This work was substantially completed in the fourth quarter of the year.

Local area supply projects with expenditures in the period include our Woodstock Area Transmission Reinforcement Project, which will increase capacity to ensure supply reliability in the Woodstock area, and our Switchyard Reconstruction Project at our Burlington Transformer Station, which will increase the load supply capacity to ensure reliability of supply to customers in the area. The GTA West Transmission Reinforcement Project, which has increased capacity to ensure supply reliability in the area, as well as the Hurontario Switching Station to Jim Yarrow Municipal Transformer Station connection, which has increased transmission capacity in the Western Brampton area to allow for future load growth, were both substantially completed in the first quarter of this year, contributing to the reduction in expenditures compared to the prior year. The final completion of our Niagara Reinforcement Project continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions related to the Niagara Reinforcement Project continue between the aboriginal peoples involved and various government entities and we expect to complete this project when site access becomes available.

Expenditures to sustain our existing transmission system were $309 million, representing an increase of $25 million compared to 2009. This increase was primarily due to increased requirements related to the refurbishment and replacement of end-of-life lines and stations and to higher targeted replacements of aging components, specifically within our breaker installation program. We also experienced increased expenditures within our protection and control equipment program compared to the prior year. These increases were partially offset by lower expenditures within our Spare Transformer Purchase and Hub Replacement Programs.

Our other transmission capital expenditures were $103 million, representing a decrease of $14 million compared to the prior year. This reduction from the prior year was due to expenditures in 2009 on our investment in an entity-wide information system replacement and improvement project which replaced end-of-life systems and improved productivity, the second phase of which was completed during the third quarter of last year. Further impacting the period are expenditures incurred to enhance information security at our Ontario Grid Control Centre, which were lower compared to the prior year as we completed a number of enhancements to meet North American Electric Reliability Corporation requirements in 2009. Partially offsetting these reductions were higher expenditures in 2010 related to the strategic purchase of power transformers in order to ensure transmission reliability through availability of critical long delivery lead time items.

Distribution

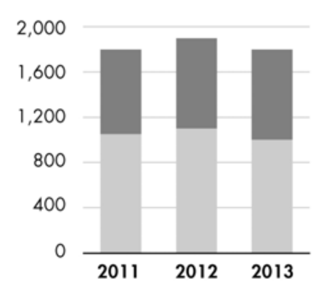
Distribution capital expenditures decreased by $14 million to $629 million in 2010, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $304 million, representing a reduction of $20 million compared to last year. We experienced reductions relating to expenditures on planned line development projects and demand line work for new connects and upgrades mainly due to a reallocation of resources to sustaining line work for line relocations. The reduction was also due to the substantial completion of smart meter installations across the province at the end of last year. During the year, these lower expenditures related to installations were partially offset by expenditures on the smart meter network infrastructure and the development and integration of the systems required for time-of-use billing, including meter reading capability and integration to the IESO meter data repository. Smart meter installations continued throughout the year as our total cumulative number of installations exceeded 1,314,000 as at December 31, 2010, thus nearing the program's total target. We currently have over 1,140,000 meters enabled to support time-of-use billing and continue our efforts to migrate our customers to time-of-use pricing; over 553,000 of our customers are now consuming power based on time-of-use pricing. Our program is one of the largest utility smart meter deployments in North America. These reductions were partially offset by the initiation of our Smart Grid Program which will enhance our operations and support distributed generation.

Expenditures to sustain our distribution system were $275 million, an increase of $28 million from 2009. This increase was primarily a result of higher requirements for transport and work equipment and the re-allocation of resources from planned line development projects to demand line work for line relocations in support of municipal road widening projects which are partially funded by the municipalities. These increases were partially offset by reduced expenditures as a result of fewer storms in 2010.

Our other distribution capital expenditures were $50 million, representing a reduction of $22 million from 2009. This reduction primarily reflects our higher prior period investments in our entity-wide information system replacement and improvement project.

Future Capital Expenditures

Our capital expenditures in 2011 are budgeted at approximately $1.8 billion. The 2011 capital budgets for our Transmission and Distribution Businesses are about $1,050 million and $750 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to be approximately $1.9 billion in 2012 and approximately $1.8 billion in 2013. These expenditures reflect the sustainment requirements of our aging infrastructure, budgeted at approximately $550 million in 2011, $700 million in 2012 and $700 million in 2013. Development projects, including smart grid, inter-area network upgrades that reflect supply mix policies to phase out coal generation, local area supply requirements and requirements to enable distributed generation, are budgeted at approximately $950 million in 2011, $950 million in 2012 and $850 million in 2013. These development investments also reflect customer demand work, distributed generation connections and the rollout of smart grid. Other capital



Future Capital Expenditures
(CAD $ millions)

expenditures amount to approximately $300 million in 2011, $250 million in 2012 and $250 million in 2013. These expenditures include the replacement of our customer billing system to address end-of-life requirements and to further productivity realization from our entity-wide SAP platform.

Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2011 to 2013, amounting to about $3.2 billion, including program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure to ensure a continued reliable supply of energy to customers throughout the province. The investment plan includes targeted component replacements of air blast circuit breakers, switchgear, autotransformers and wood pole structures to maintain the performance of assets. Also, the reconstruction of transformer stations is planned for the Burlington TS 115 kV, Leaside, Hearn and Manby stations to ensure future reliability. These sustaining investments are necessary to ensure that we will continue to meet all regulatory, compliance, safety and environment objectives.

Inter-area network projects, required to accommodate new generation related to supply mix policies, include our Bruce to Milton Transmission Reinforcement Project to connect nuclear generation and new wind generation in the Huron-Grey-Bruce area. This project is anticipated to be in service in 2012. We are also installing station equipment, including SVCs in Southwestern Ontario, to increase transmission capacity. This equipment will mitigate congestion and enhance the transfer capability between Northern Ontario and Southern Ontario and the transmission system north of Sudbury enabling new hydroelectric generation.

The budgeted capital expenditures do not include any amounts associated with new lines projects articulated in the September 21, 2009 letter to us from the then Minister of Energy and Infrastructure. We suspended work on those projects after the Minister of Energy and Infrastructure requested our Company to focus on those items that are essential to the safe and reliable operation of our existing assets or projects already under development and approved by the OEB, or are critical to the connection of renewable generation projects that have been identified by the OPA as part of the government's green energy agenda. In addition, in August 2010, the OEB introduced competition for transmission expansion projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansion under the OEB's competitive framework.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work to advance specified transmission projects and upgrades to the system that will safely and reliably accommodate additional renewable energy from small generation projects. According to the LTEP, we are expecting to receive direction to carry out the three specified projects. These transmission projects, which are identified in the LTEP, include:

- Southwestern Ontario Series Compensation
- Reconductoring Sarnia to London circuits
- New transmission line west of London

While our current budget does not include the estimated capital expenditures associated with these projects and upgrades to the system, they could be up to approximately $1 billion over a period to the in-service dates of these projects.

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

Distribution

Capital expenditures for the period 2011 to 2013 are estimated to be approximately $2.3 billion, including capital expenditures to support the sustainment of our capital infrastructure. Our core work will continue to focus on the performance of our aging distribution asset base in order to improve system reliability. There is a continuation of investments to replace end-of-life equipment and components, implement smart grid and focus on wood pole replacements and submarine cables to address deteriorating assets. In addition, we will continue to address the demand for new load connections, trouble calls, storm restoration and system capability reinforcement.

Our Distribution sustainment work program has been reduced consistent with the decision on our distribution application for the 2010 and 2011 rate years and as a result our work program will include in it a gradual increase in our intended Wood Pole Replacement Program to address the aging poles and deterioration.

Distribution development expenditures over the period are primarily related to customer demand work such as connections and upgrades, smart grid, distributed generation connections, including station upgrades, protection and control, new lines and some contestable work for which we receive capital contributions. During the 2011 and 2012 period we are managing a significant number of projects throughout the province to address load growth and the stress on our system components.

Distributed generation expenditures are based on our estimate of the number of anticipated connections, taking into account the most recent data available from the OPA. Although distributed generation demand is expected to increase over the planning period, connection work is contestable and therefore the volume of work could fluctuate.

The Company's current billing system is near end of life, and costly to maintain and operate. The replacement of this system is anticipated to commence in 2011 and be completed by 2014.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations under Canadian GAAP, as well as other major commercial commitments:

December 31, 2010 (Canadian dollars in millions)	**Total**	**2011**	**2012/2013**	**2014/2015**	**After 2015**
Contractual Obligations *(due by year):*					
Long-term debt – principal repayments	7,775	500	1,200	1,000	5,075
Long-term debt – interest payments	6,599	405	732	614	4,848
Inergi LP (Inergi) outsourcing agreement[1]	569	143	274	152	-
Operating lease commitments	53	5	14	9	25
Environmental and asset retirement obligations[2]	391	23	60	73	235
Total Contractual Obligations[6]	15,387	1,076	2,280	1,848	10,183
Other Commercial Commitments *(by year of expiry)*:					
Bank line[3]	1,250	-	1,250	-	-
Letters of credit[4]	114	114	-	-	-
Guarantees[4]	326	326	-	-	-
Pension[5]	307	145	162	-	-
Total Other Commercial Commitments	1,997	585	1,412	-	-

[1] On May 1, 2010, the Company extended the Master Services Agreement with Inergi for a further three-year period. The term of the agreement, which would have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

[2] We record a liability for the estimated future expenditures associated with the phase-out and destruction of PCB-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands as well as asset retirement obligations for the removal of asbestos-contaminated material from our facilities and the decommissioning and removal of our switching station located at Ontario Power Generation's Abitibi Canyon Generating Station. The expenditure pattern reflects our planned work program for the period.

[3] As a backstop to our commercial paper program, we have a $1,250 million revolving standby credit facility with a syndicate of banks which matures in June 2013.

[4] We currently have bank letters of credit of $113 million outstanding relating to retirement compensation arrangements (RCAs). The other $1 million included in letters of credit pertains to operating letters of credit. On November 1, 2010, we increased our letter of credit related to RCAs to approximately $113 million from $107 million. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million and on behalf of two distributors using guarantees of up to a maximum of $660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[5] Contributions to the pension fund are made one month in arrears. Contributions for 2011 are based on an actuarial valuation filed in September 2010 and effective December 31, 2009. Our annual pension contributions for 2011 and 2012 will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we estimate our minimum pension contributions to be approximately $145 million in 2011 and $149 million in 2012 based on the level of pensionable earnings. Contributions for 2013 will be based on an actuarial valuation effective December 31, 2012.

[6] In addition, the Company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these agreements are considered individually material, and the majority do not extend beyond December 31, 2011.

The amounts in the above table under long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures. Expenditures resulting from our environmental programs and asset retirement obligations are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the OEFC. In January 2010, we purchased $250 million of Province of Ontario Floating Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Effect of Load on Revenue

The load is expected to decline in 2011 due to the impact of CDM and Embedded Generation, partially offset by load growth associated with economic growth in all sectors of the Ontario economy. Overall load growth due to the economy alone is forecasted to be approximately 1.0%, with the industrial sector slightly outperforming residential and commercial sectors. The load impact of CDM and Embedded Generation is expected to have a substantial negative impact on load growth of approximately 2.0% and 0.3%, respectively. On the whole, load is expected to decline by about 1.3%. A reduction in load, beyond our load forecast included in our approved revenue requirement, would negatively impact our financial results.

Effect of Interest Rates

Changes in interest rates will impact the calculation of our revenue requirements filed with the OEB. The first component impacted by interest rates is the return on equity. The OEB-approved adjustment formula for calculating return on equity will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in the current OEB formula for determining our rate of return on equity would reduce our Transmission Business' results of operations by approximately $16 million and our Distribution Business' results of operations by approximately $10 million. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

Input Costs and Commodity Pricing

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

Debt Financing

Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund capital expenditures or meet debt maturity repayments and other liquidity requirements (see Risk Management and Risk Factors – Risk Associated with Arranging Debt Financing). We rely on debt financing through our MTN Program and Commercial Paper Program. Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities as of December 31, 2010, which is comprised of a $1,250 million syndicated bank line of credit and the holding of $250 million of Province of Ontario Floating Rate Notes. In 2010, we continued issuing sufficient cost-effective debt financing through the MTN Program and Commercial Paper Program in the Canadian capital markets and we arranged sufficient available liquidity. Economic conditions continue to improve from the credit crisis of late 2008.

Pension

During 2010, the deferred pension asset reported on our Balance Sheet increased by $36 million to $460 million. We contributed $143 million into our pension plan in 2010 and made an additional payment of $48 million in December. We incurred $154 million in net periodic pension benefit cost. On an accounting basis, the 2009 unfunded benefit obligation of $230 million increased by $67 million to $297 million. The plan experienced positive returns of about 9.96% in the year. However, the plan was also impacted by an increase in the accrued benefit obligation, primarily as a result of a decrease in the discount rate used for accounting purposes (see Critical Accounting Estimates – Employee Future Benefits).

RISK MANAGEMENT AND RISK FACTORS

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our Company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprised of direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our Company. Our Chief Risk Officer is responsible for the ongoing monitoring and reviewing of our risk profile and practices, and our Executive Vice-President and Chief Financial Officer is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, are required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Executive Vice-President and Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our Company. Pursuant to such agreement, in September 2008 the Province made a declaration removing certain powers from our Company's directors pertaining to the off-shoring of jobs under the outsourcing arrangement with Inergi LP. In 2009, the Province required Hydro One, among other agencies, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Hydro One's credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of Hydro One's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our Company, the Province's ownership of Ontario Power Generation Inc. (OPG), and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us, which could have a material adverse effect on our business.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be materially adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively affected by successful CDM programs. The recently proposed LTEP directs the OPA to achieve interim CDM targets of 4,550 MW of provincial summer peak demand and 13 TWh of cumulative energy savings by the end of 2015. The Minister of Energy and Infrastructure's March 31, 2010 directive set a province-wide LDC CDM target of 1,330 MW and 6,000 GWh for the period 2011-2014. Our targets have been set at 214 MW and 1,130 GWh for the period 2011-2014. These expectations are factored into our revenue requirements for OEB approval, to ensure that the targeted CDM accomplishments do not result in deteriorated revenues. There is a risk that our revenues would be reduced if these targets are exceeded. In September 2010, the Conservation and Demand Management Code for Electricity Distributors was established and sets out the obligations and requirements that licensed distributors must comply with in relation to the CDM targets set out in their licenses. This code also sets out the conditions and rules that licensed distributors are required to follow if they choose to use OEB-approved CDM programs to meet their CDM targets. The implementation of this code could further deteriorate revenues without appropriate compensation. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of any such compensation mechanism is yet to be determined. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

In response to the LTEP, we expect to make investments in the coming years to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets, particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations, which could have a material adverse effect on our Company.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt which mature between 2011 and 2014, including $500 million maturing in 2011 and $600 million maturing in 2012. We plan to incur capital expenditures of approximately $1.8 billion in 2011 and capital expenditures are expected to increase to approximately $1.9 billion in 2012. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our Company.

Risk Associated with Transmission Projects

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

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

With the introduction on August 26, 2010 of the OEB's competitive transmission project development planning process, all interested transmitters will be required to submit a bid to the OEB for identified enabler facilities and network enhancement projects. Historically, we would have been awarded such projects through our rates and Section 92, Leave to Construct, applications. The facilitation of competitive transmission could impact our future work program and our ability to expand our current transmission footprint. In addition, bid costs are only recoverable by the successful proponent.

Asset Condition

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

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

Work Force Demographic Risk

By the end of 2010, approximately 18% of our employees were eligible for retirement and by 2012 there may be about 22% eligible to retire. Accordingly, our success will be tied to our ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as we expect the skilled labour market for our industry to be highly competitive in the future. In addition, many of our employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. We have already lost a considerable number of management staff, both those in executive positions and those who are logical successors for executive positions. Moreover, we must also continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, it could have a material adverse effect on our business.

Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of our Board of Directors that has governance over environmental matters. Given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee, however, that all such risks will be identified and mitigated without significant cost and expense to our Company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation (LAR) program covering most of our stations and service centres. This program involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our Company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's polychlorinated biphenyl (PCB) regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025 while our LAR expenditures are expected to be incurred over the period ending 2020. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

As a result of regulatory changes, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. With the assistance of an external expert, we completed a study to estimate the expenditures associated with removing such materials from our facilities. We used this information to record an asset retirement obligation at December 31, 2010.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases.

We anticipate that all of our future environmental expenditures will continue to be recoverable in future electricity rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on our Company.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities. Any of these could have a material adverse effect on our Company.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. Although security and system disaster recovery controls are in place, system failures or security breaches could have a material adverse effect on our Company.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2009 and was filed in September 2010. Our Company contributed $145 million to its pension plan in respect of 2010 to satisfy minimum funding requirements. A one-time additional payment of $48 million was made in December 2010. Contributions beyond 2010 will depend on investment returns, changes in benefits and actuarial assumptions, and may include additional voluntary contributions from time to time. Nevertheless, future contributions are expected to be significant. A determination by the OEB that some of our pension expenditures are not recoverable from customers could have a material adverse effect on our Company, and this risk may be exacerbated as the quantum of required pension contributions increase.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our Company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach, which is in part based on the forecast for long-term Government of Canada bond yields. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Business' net income by approximately $16 million and our Distribution Business' net income by approximately $10 million. Our net income is adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counter-parties. We do not trade in any energy derivatives. We do, however, have interest rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlements Code. The failure to properly manage these risks could have a material adverse effect on our Company.

Labour Relations Risk

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

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the $761,500 that we paid to these Indian bands and bodies in 2010. If we cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we amended and extended our outsourcing services agreement with Inergi LP, effectively renewing the arrangement until February 28, 2015. If the agreement with Inergi LP is terminated for any reason, we could be required to incur significant expenses to transfer to another service provider, which could have a material adverse effect on our business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2010 amounted to $1,055 million and principally relate to future income tax, environmental costs and the pension variance account. We have also recorded regulatory liabilities amounting to $612 million as at December 31, 2010. These amounts pertain primarily to deferred pension, the external revenue variance account, future income tax and retail settlement variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to satisfy obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of assets contaminated with PCB-laden mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work and make assumptions for when the future expenditures will actually be incurred in order to generate future cash flow information. A long-term inflation assumption of 2% has been used to express our current cost estimates as estimated future expenditures. Future estimated LAR expenditures are expected to be incurred over the period ending 2020 and are discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when an increase in obligation was first recorded. Consistent with the requirements of Environment Canada's PCB regulations issued on September 17, 2008, estimated future PCB remediation expenditures are expected to be incurred over the period ending 2025 and are discounted using factors ranging from 5.14% to 6.25%, depending on the appropriate rate for the period when an increase in obligation was first recorded.

Recording a liability now for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination; the number of assets to be inspected, tested and mitigated; oil volumes; and contamination levels of equipment with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates based on our planned approach of meeting current legislative and regulatory requirements. These include Environment Canada's regulations governing the management, storage and disposal of PCBs. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation estimates and the actual pattern of annual future cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (the Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions in respect of 2010 were approximately $193 million, $145 million of which was based on an actuarial valuation effective December 31, 2009. Contributions after 2012 will be based on an actuarial valuation effective December 31, 2012, and will depend on investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 6.50% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was 63% exposure to equities, 33% to fixed income and 4% in alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the Fund's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. In the short-term, the plan can experience aberrations in actual return. In 2010, the return on pension plan assets was higher than this long-term assumption.

The discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2010 decreased to 5.75% from 6.50% used at December 31, 2009 in conjunction with decreases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities.

Yields on AA corporate bonds decreased by approximately 70-120 basis points between December 31, 2009 and December 31, 2010. Based on the duration of the plan's liabilities, discount rates would be 5.75% per annum for each of the pension plan, the post-retirement benefit plan and the post-employment plan. The overall discount rate applied to all plans for liability valuation purposes as at December 31, 2010 was 5.75%.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has increased from approximately 2.50% per annum as at December 31, 2009 to within the range of 2.25%-2.50% per annum as at December 31, 2010. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current implied rate is too high to be used as a long-term assumption and as such, has used a 2.00% per annum inflation rate for liability valuation purposes as at December 31, 2010.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $15 million per year and an increase in the year-end obligation of about $185 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as the cost of fixed assets.

Goodwill and Asset Impairment

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2010 and we determined that the carrying value of our goodwill has not been impaired.

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

STATUS OF OUR TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles (GAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011, with comparative data also reported under IFRS. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their adoption of IFRS for one year. We plan on adopting the one-year deferral and therefore will adopt IFRS for our fiscal year beginning on January 1, 2012.

In anticipation of the 2008 decision from the AcSB, we commenced our IFRS conversion project in 2007. The project has four separate phases: diagnostic, design and planning, solution development, and implementation. We completed the diagnostic phase in 2008. It involved a high-level review and identification of the major differences between current GAAP and IFRS in all subject areas, resulting in the identification of the areas of accounting difference with the highest potential to significantly impact our Company.

In 2009, we completed the design and planning and the solution development phases of our project, including substantial completion of all our policy analyses. We are currently engaged in the implementation phase which is the final phase of our project. We are preparing to begin tracking our comparative results under IFRS next year. Our teams continue to monitor progress relative to key milestones, monitor developments of both the International Accounting Standards Board (IASB or the Board) and the AcSB, update recommendations and develop financial reports. We continue to have ongoing dialogue with our external auditors about possible outcomes of our project.

We continue to evaluate the impacts of current and prospective IFRS on all of our business activities, including those of our subsidiaries and the impact on our entity-wide information system. We are simultaneously analyzing the impacts of changes on our disclosure controls and internal controls over financial reporting, our debt covenants and our performance measures. We continue to provide formal communications to our employees. We have completed numerous staff training sessions and will plan for future training sessions as standards continue to evolve.

Accounting Policies

The areas with the highest potential to significantly impact our Company upon conversion to IFRS, identified during the diagnostic phase, are regulatory assets and liabilities, fixed-assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS* (IFRS 1).

Property, Plant and Equipment

On May 6, 2010, the IASB issued the omnibus *Improvements to IFRS*, which included an amendment to IFRS 1 applicable to entities with RRA. It includes transition relief for first-time adopters by offering an optional exemption to use the carrying amount of fixed assets or intangible assets as deemed cost on the transition date when the carrying amount includes costs that would not otherwise qualify for capitalization. We will elect this exemption for our regulated businesses.

Regulatory Assets and Liabilities

RRA is not permitted under IFRS. RRA affects the timing of the accounting recognition of costs, revenues, losses and gains. The inability to recognize regulatory assets and liabilities after implementing IFRS in 2012 will impact our statement of operations by causing a change in the timing of recognition of these amounts. In the absence of rate-regulated accounting, the write-off of our regulatory assets and regulatory liabilities would have resulted in a net reduction to retained earnings of approximately $249 million as at December 31, 2010.

In-Progress Construction and Development

Current IFRS are significantly different from Canadian GAAP in terms of the expenditures that can be capitalized to in-progress construction and development programs and projects. Certain fixed asset and intangible asset expenditures are ineligible for capitalization under IFRS. In the absence of rate-regulated accounting, the estimated impact on our financial statements would have been a reduction of approximately $300 million in capital expenditures and an increase of approximately $300 million in operations, maintenance and administration expenditures had this accounting been followed in 2010. For 2012 rates, the OEB directed our Company to adopt this change in accounting classification for ineligible expenditures in determining the revenue requirement of our Transmission Business. We currently have approval for a deferral account for such expenditures within our Distribution Business and we anticipate applying for revenue requirement treatment, consistent with that directed for our Transmission Business, in our next distribution rate application.

Employee Future Benefits

In the absence of RRA, the continuation of accounting for expenditures related to employer-sponsored pension plans on a cash basis is not permissible. Regulatory assets and liabilities, representing the cumulative difference between our Company's pension contributions currently accounted for on a cash basis at the direction of the regulator, and the costs that would be recognized on an accrual basis under Canadian GAAP, would not meet the definition of assets or liabilities under IFRS and hence will require de-recognition at the IFRS transition date. We have assessed our options with respect to the recognition of accumulated, unamortized actuarial gains and losses associated with employment benefits. The possible alternatives to account for these pension and other employee benefit amounts include charging unamortized actuarial gains and losses immediately upon adoption under IFRS 1 or recognizing an adjustment to those amounts retrospectively to comply with IAS 19, *Employee Benefits* (IAS 19). In the absence of rate-regulated accounting, we intend to recognize a retrospective adjustment for these amounts under IAS 19, without the IFRS 1 exemption. The impact of adopting IAS 19 retrospectively at December 31, 2010 would have been a reduction to retained earnings of $319 million.

In April 2010, the IASB published an exposure draft, *Defined Benefit Plans (Proposed Amendments to IAS 19 Employee Benefits)*, with significant implications for both financial position and income reporting. Deferred recognition of actuarial gains and losses would be eliminated and instead all changes in the defined benefit obligation and in the fair value of plan assets would be recognized in the Statement of Comprehensive Income when those changes occur. The exposure draft also proposed a new presentation approach where the changes in the defined benefit obligation and the fair value of plan assets would be segregated and separately disclosed as service cost, finance cost and re-measurement adjustments. Service cost and finance cost components would be recognized in the Statement of Operations. The re-measurement adjustments representing actuarial gains and losses would be recognized as part of other comprehensive income. As per the IASB's revised timeline, the final standard is expected in the first quarter of 2011 with an effective date not earlier than 2013. The new accounting standard when adopted in 2013 or in later years will result in higher volatility in the Statement of Comprehensive Income due to the recognition of the full amount of actuarial gains and losses.

Payments in Lieu of Corporate Income Taxes

We recognize future tax assets and liabilities in accordance with Canadian Institute of Chartered Accountants Handbook section 3465, *Income Taxes*, which was amended effective January 1, 2009 to bridge the convergence to IFRS. As such, we have determined that there is no potential for a significant impact for this class of transactions based upon contingent outcomes regarding transactions for payments in lieu of corporate income taxes. Without RRA, the impact on our provision for payments in lieu of corporate income taxes would be recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result the provision for PILs for the year ended December 31, 2010 would have been higher by approximately $100 million including the impact of a change in substantively enacted tax rates.

OEB Consultation

On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. The OEB has initiated a second phase of its consultative process to amend certain regulatory instruments. We are continuing to assess the impact of the OEB's report and other recommendations on our IFRS conversion project.

On February 24, 2010, the OEB issued a letter to all licensed electricity distributors and rate-regulated natural gas utilities for the purpose of clarifying the OEB's view released in July on accounting for overhead costs in the cost of new capital works effective January 1, 2011. The OEB stated in the letter that it would be requiring full compliance with IFRS requirements, including those in IAS 16, *Property, Plant and Equipment* (IAS 16), as applicable to non-regulated enterprises and only where the OEB authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable. We continue to assess this guidance in light of the AcSB's revised implementation date.

On November 8, 2010, the OEB published an amendment to a report it made on its policy, *Transition to International Financial Reporting Standards*. In response to the AcSB allowing rate-regulated entities the option to delay their adoption of IFRS to January 1, 2012, the OEB has adjusted certain policy statements in the report to account for this choice.

On November 17, 2010, the OEB initiated a working group to develop recommendations on how IFRS should be implemented together with IRM rate setting as well as issues that impact utilities under cost-of-service. We are actively participating in the working group.

Internal Control over Financial Reporting and Disclosure Controls and Procedures

We are continuously analyzing the impacts of changes on our disclosure controls and procedures and internal controls over financial reporting as we proceed through our implementation of IFRS. Additional disclosure controls may be required to address first-time adoption and additional internal controls may be required to implement changes in our accounting policies and to support our ongoing IFRS reporting requirements.

We have initiated the process of analyzing our current disclosure control and procedure and internal control documentation to identify changes required upon the adoption of IFRS. We have categorized each control process as low, medium or high-impact, based on the currently assessed risk of a major change being required upon implementation of IFRS. This ranking was completed in the fourth quarter of 2009. We completed updating the documentation for all of the low and medium-risk processes with IFRS implementation impact, including process documentation and risk and control matrices, during the second quarter of 2010. Completion of our documentation revisions for our high-risk processes had been put on hold pending an anticipated decision from the IASB on the allowance of rate-regulated accounting under IFRS due to the impact that would have had on these processes. We plan to initiate the completion of the revisions to our high-risk processes in the first quarter of 2011 now that there is certainty that RRA will not be permitted upon our adoption of IFRS. Once our high-risk process documentation has been updated, we will begin walkthroughs of all of our revised process and control documentation for low, medium and high-risk processes. At this time we estimate that we will complete this on a timely basis for reporting under IFRS in 2012.

Financial Reporting Expertise

The project's formal governance structure includes a steering committee consisting of senior level management from finance, information technology, treasury and our operations organizations. Project status reporting is provided to senior executive management and to the Audit and Finance Committee of our Board of Directors on a quarterly basis, or more often as necessary.

The training of key finance and operational staff commenced in 2007 and has been ongoing. Training has also been given to the Audit and Finance Committee and senior executive management to communicate the key differences between Canadian GAAP and IFRS, and to provide them with an overview of the key impacts conversion could have on our financial statements. These groups are updated as developments in IFRS continue. Due to the extensive staffing requirements associated with such a large-scale project, an external expert advisor was engaged to assist with our IFRS conversion project, from the planning phase through to implementation.

The Audit and Finance Committee and senior management continue to be updated for key developments in IFRS and their potential impact on our financial statements. Updates are provided on at least a quarterly basis. This will continue through to our conversion to IFRS in 2012. During the third quarter we continued to provide training to our key finance and operational staff. To date, they have been trained in many key areas including property, plant and equipment, regulatory accounting, revenue recognition, liabilities, employee benefits, financial instruments and most recently income taxes. In addition to sessions on specific topics, we have also held one financial reporting update session. During the next year, we will continue to provide IFRS financial reporting update sessions on a regular basis.

Business Activities

The Company has the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. Depending on the outcome of various exposure drafts under IFRS, we could undergo changes to our results that would impact our debt covenants. For example, covenants would be impacted as a result of de-recognition of regulatory assets and liabilities, accounting for expenditures related to employer-sponsored pension plans on an accrual basis versus a cash basis and the change in costs that are allowable versus disallowable for capitalization as part of the cost of self-constructed assets. As part of our IFRS transition project, we have been analyzing the impact of potential changes in accounting policy on our debt covenants and communicating potential scenarios and impacts analyses to our Audit and Finance Committee. Based on our current estimates, we would remain in compliance with our debt covenants. However, we met with our financial institutions and amended our credit agreement with the syndicate of banks to consider the potential impacts that IFRS may have on our covenants. Specifically, the calculation of our debt to total capitalization ratio was modified under this agreement for certain items to factor in IFRS impacts, such that the debt to total capitalization ratio is representative of what it was prior to IFRS. The same ratio is used to support the indenture agreement with our bondholders. Given our current estimates, the indenture agreement was not updated at that time because we anticipated that we would remain within the threshold for our debt to capitalization ratio given the information available at the time. We have continued to monitor the impact of conversion on our debt covenants as IFRS develops and as we finalize our policy choices under IFRS. With the recent deferral of the IASB RRA project, we intend to re-assess the impact on our debt to capitalization ratio and identify appropriate next steps.

Information Technology (IT) Systems

As part of an entity-wide system improvement project, many of our major financial systems were replaced in 2008 and 2009. To ensure that the future requirements of IFRS would be met, common team members were included within the governance structure of our IFRS project and the new entity-wide system implementation team. At the same time, members of the IFRS implementation team were involved in the design of our new entity-wide system. IT implications were identified and assessed during our diagnostic and design and planning stages of our IFRS project and were incorporated in the project's solution development stage. For example, the new system has been configured to track depreciation on a component level, based on the useful life of the asset, as currently required under IAS 16. The new system has also been configured to track allowable versus disallowable costs for capitalization under IAS 16. The system was designed with the maximum flexibility given the uncertainty of the outcome of certain impactive IASB projects at the time. When the AcSB deferred implementation of IFRS for rate-regulated entities, we began making the required changes to continue reporting under Canadian GAAP until January 1, 2012. We have substantially completed required changes to our systems in order to have them ready to report under IFRS beginning on January 1, 2012, with comparatives.

Environmental Reporting

We currently record environmental liabilities for the estimated future expenditures to comply with regulations that require us to remediate certain environmental issues. Specifically, we have obligations related to PCB-contaminated equipment, chemically-contaminated lands adjacent to certain of our properties, and buildings that have asbestos-containing materials. We also currently record an asset retirement obligation (ARO) for the removal and disposal of asbestos-containing materials from some of our buildings. These obligations are recorded based on the present value of the future estimated cash flows. Under Canadian GAAP this present value is calculated using a fixed discount rate which is the credit-adjusted risk-free rate at the date of recognition. When we transition to IFRS, we will be required to reassess this discount rate and, as it will no longer be fixed, we will be required to adjust it at each balance sheet date. The impact of this change on our recorded obligations cannot be predicted at this time as it will depend on future economic conditions.

Under Canadian GAAP, an ARO exists where there is a legal obligation to remove and dispose of an asset or remediate a contaminated site. Under IFRS an ARO also includes obligations that are not legal but which are constructive in nature. Such a constructive obligation may be inferred from other factors such as a reporting enterprise's policies, actions or public statements. Under IFRS, new constructive obligations will be recorded as

AROs in cases where we expect that specific lands will no longer be used for operational purposes and where we expect to remove assets or remediate properties.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Consistent with transitioning our financial systems to an SAP enterprise-wide platform as part of the entity-wide information system replacement and improvement project, we successfully implemented various Finance, Human Resources, Payroll and Investment Management modules in 2009. The reporting tool Business Intelligence/Business Warehouse was also implemented. This implementation included new controls over Internal Controls over Financial Reporting (ICFR) and the replacement of other controls in the previous environment. Our process documentation has been updated and the design and effectiveness of the controls have been tested.

A Supply Chain Enhancement Project to develop an operating framework that outlines the strategy and objectives of supply chain is expected to be completed in 2011. The resulting new processes are currently being reviewed to assess the impact on the control environment. Process documents will be updated and controls will be tested for design and operating effectiveness in 2011.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2010, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to our Company is made known within our Company. Based on the evaluation of the design and operation of our DC&P, our certifying officers concluded that our DC&P was effective as at December 31, 2010. Further, our Certifying Officers have also certified that ICFRs have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements. Based on the evaluation of the design and operating effectiveness of the Company's ICFR, our Certifying Officers concluded that our ICFR was effective as at December 31, 2010.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2008, 2009 and 2010. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statements of Operations *Year ended December 31 (Canadian dollars in millions, except earnings per common share)*	**2010**	**2009**	**2008**
Revenues	5,124	4,744	4,597
Net income	591	470	498
Basic and fully diluted earnings per common share	5,727	4,528	4,797

Consolidated Balance Sheets *Year ended December 31 (Canadian dollars in millions, except cash dividends per share)*	**2010**	**2009**	**2008**
Total assets	17,322	15,635	13,878
Total long-term debt	7,778	6,881	6,133
Cash dividends per common share	100	1,700	2,410
Cash dividends per preferred share	1.375	1.375	1.375

OUTLOOK

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

The LTEP continues the energy strategies set out in the GEA introduced in 2009. The need to rapidly reduce the energy sector's carbon footprint dominates current environmental decision-making, leading to high expectation for immediate action and expansion of clean energy supply. Emerging technologies and the need to connect clean and renewable generation challenges our Transmission and Distribution Businesses to recalibrate and establish a more flexible and smart electricity grid.

We are planning significant investments in transmission and distribution infrastructure and the continued proactive maintenance of our assets to ensure the electricity system's reliability in the public interest. Our investment plan supports the achievement of the Province's phase-out of coal-fired generation, renewable and nuclear objectives, facilitates the development and use of renewable energy resources, promotes system efficiency, sustains equipment performance, meets customers' service quality needs and facilitates the integration of new supply.

In 2010, the OEB approved our 2011 distribution rates with a revenue requirement of approximately $1,218 million. The revenue requirement approved was lower than requested, but should continue to support our work programs necessary to sustain our critical infrastructure, increase reliability through enhanced forestry management, support the smart meter requirements and invest in a sustainable electricity system that supports renewable generation. We will monitor and address any associated risks should they arise. We will be preparing evidence to support a potential distribution rate application for the years 2012 and 2013.

In early 2011, the OEB approved our 2011 and 2012 transmission rates, with revenue requirements of approximately $1,346 million and $1,658 million, respectively. The approved revenue requirements will continue to support aging critical infrastructure, area supply projects and the Province's policy objectives. The 2012 revenue requirement includes the OEB's direction to adopt IFRS accounting for indirect overheads capitalized resulting in a $200 million shift between capital expenditures and operating expenses.

The actual timing and expenditures in our plan are predicated on obtaining various approvals including OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities. Further, we have made assumptions in the plan regarding cost responsibility and funding, consistent with the GEA regulations and amended TSC and DSC.

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

Key enablers of the successful implementation of our work program are our human and material resourcing strategies. Our human resource strategy is focused on hiring through our association with universities, colleges and our unions, as well as skills development and retention. Significant retirement projections and increasing work volumes will result in an unprecedented number of new hires in the near term. With regard to materials, we are seeing increasing lead times and costs as market shortages emerge globally. Consequently, materials sourcing strategies continue to be developed and implemented to ensure the availability of materials to support our work programs.

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

We will continue to increase enterprise value through productivity improvements and cost-effectiveness driven by technology. Over the last two years, we have replaced most of our core systems with an enterprise-wide information technology system. We will leverage this investment as a platform for further effectiveness and efficiency gains, including enhancements in strategic sourcing. In addition, significant opportunity resides with smart meters and the proliferation of a smart grid, including energy efficiency, demand response and distributed-resources technologies.

Through the outlook period, we anticipate no changes to our role within the industry and expect that our financial returns will be sufficient to maintain our credit quality.

APPOINTMENT OF JANET HOLDER

On July 1, 2010, Janet Holder was appointed to our Board of Directors. Ms. Holder is the President of Enbridge Gas Distribution and serves on the Board of Governors at the University of New Brunswick.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our Company. Such statements include, but are not limited to statements about our strategy and our performance measures and targets; statements related to the IPSP; statements about smart meters including their capabilities, their timing of installation and our focus on building an advanced distribution solution that will leverage our smart meter investment; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including the impacts of changes to codes, licences, rules, new regulatory guidelines, tariff rate changes, cost recovery, return on equity, rate structures, revenue requirements and impacts on an average customer's total bill; expectations regarding the timing and content of applications to, hearings with and decisions from the OEB and other regulatory bodies; statements related to the LTEP; expectations regarding the OEB's Framework for Transmission Project Development Plans; statements about outstanding legal proceedings; statements regarding time-of-use billing; expectations regarding future renewable energy generation; statements regarding our liquidity and capital resources and their use; expectations regarding our financing activities, including our capital management objectives and our ability to access the capital markets; expectations about our maturing debt and interest payments; expectations regarding the results of our ongoing and planned projects and/or initiatives and their completion dates; statements regarding expected future capital expenditures, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commitments; statements regarding the effect of load on our revenue including the anticipated impact of CDM programs; the effect of interest rates on our revenue requirements and results of operations; statements regarding the estimated impact of changes in the forecasted long-term Government of Canada bond yield on our results of operations; impacts to our business in respect of the adequacy and timing of supply of materials, supplies and services and credit risk of our counterparties; expectations regarding future pension contributions, effect of health care cost trend on the future benefits costs and the performance of our pension plan; the possibility of the Province making declarations pursuant to our memorandum of agreement with them; statements regarding possible future actions of the Province and regulatory bodies; expectations regarding connections of new generation to our transmission and distribution systems; expectations regarding asset condition; statements regarding workforce demographics and the market for skilled labour; statements regarding the amount and timing of future estimated environmental expenditures, including with respect to LAR and PCBs; statements about future asbestos removal expenditures and asset retirement obligations; expectations regarding our information technology strategy and enterprise reporting system; the possibility that we could in future decide to issue foreign currency-denominated debt; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements about our outsourcing arrangement with Inergi LP; statements regarding provincial ownership of our transmission corridors; statements about critical accounting estimates; statements about IFRS, our conversion to IFRS and the effect of the absence of rate-regulated accounting under IFRS; statements about the outlook period including our expectations regarding our role within the industry, our financial returns, our credit rating and credit quality and structural changes to our Company. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," "goal," "aim," "target," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission Businesses; a stable regulatory environment; the preparation of business plans, regulatory filings and future capital expenditures on the basis that commencing 2011 rate-regulated accounting will not be permitted under IFRS; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things.

- the impact of the GEA and the LTEP, including unexpected expenditures arising therefrom;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- the timing and results of regulatory decisions regarding our revenue requirements, cost recovery and rates, as well as changes to rules under various regulatory body review;
- the potential impact of CDM programs on our load and our revenues;
- unanticipated changes in electricity demand or in our costs;
- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk that we may not recover all of our project costs to prepare a bid associated with the OEB's Framework for Transmission Project Development Plans;
- the risk that we will be unable to source the materials necessary to support our work programs;

- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;

- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;

- the risk of currently undetermined future asbestos removal costs;

- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;

- the risks associated with information system security and with maintaining a complex information technology systems infrastructure and transitioning most of our financial and business processes to an integrated business and financial reporting system;

- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;

- the risks associated with changes in interest rates;

- the inability to negotiate collective agreements consistent with our rate orders or in a timely fashion and the potential for labour disputes;

- the risk that we may incur significant costs associated with transferring assets located on Indian lands;

- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi LP is terminated;

- the impact of the ownership by the Province of lands underlying our transmission system; and

- the impact of the final outcome of the exposure draft on rate-regulated accounting under IFRS.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Management and Risk Factors" in this Management's Discussion and Analysis (MD&A). You should review this section in detail.

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

This MD&A is dated as at February 10, 2011. Additional information about our Company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

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, 2011.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition internal and disclosure controls have been documented, evaluated, tested and identified consistent with National Instrument 52-109 (Bill 198). An internal audit function evaluates the effectiveness of these internal controls consistent with its annual audit plan and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with accounting principles generally accepted in Canada. The Independent Auditors' Report, which appears on page 43, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer and Executive Vice-President and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting pursuant to National Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Laura Formusa	Sandy Struthers
President and Chief Executive Officer	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, 2010 and December 31, 2009, the consolidated statements of operations and comprehensive income, retained earnings and accumulated other comprehensive income, and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Hydro One Inc. as at December 31, 2010 and December 31, 2009, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
February 10, 2011

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (Canadian dollars in millions, except per share amounts)	**2010**	**2009**
Revenues		
Transmission *(Note 16)*	1,307	1,147
Distribution *(Note 16)*	3,754	3,534
Other	63	63
	5,124	4,744
Costs		
Purchased power *(Note 16)*	2,474	2,326
Operation, maintenance and administration *(Note 16)*	1,078	1,057
Depreciation and amortization *(Note 3)*	583	537
	4,135	3,920
Income before financing charges and provision for payments in lieu of corporate income taxes	989	824
Financing charges *(Note 4)*	342	308
Income before provision for payments in lieu of corporate income taxes	647	516
Provision for payments in lieu of corporate income taxes *(Notes 5 and 16)*	56	46
Net income	591	470
Other comprehensive income	-	-
Comprehensive income	591	470
Basic and fully diluted earnings per common share *(Canadian dollars) (Note 15)*	5,727	4,528

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**
Retained earnings, January 1	1,791	1,497
Change in accounting policy for the recognition of future income tax assets and liabilities *(Note 2)*	-	12
Net income	591	470
Dividends *(Note 15)*	(28)	(188)
Retained earnings, December 31	2,354	1,791

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**
Accumulated other comprehensive income, January 1	(10)	(10)
Other comprehensive income	-	-
Accumulated other comprehensive income, December 31	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2010**	**2009**
Assets		
Current assets:		
Cash	33	-
Short-term investments *(Note 17)*	139	-
Accounts receivable (net of allowance for doubtful accounts - $25 million; 2009 - $25 million) *(Note 16)*	911	843
Regulatory assets *(Note 8)*	42	72
Materials and supplies	21	21
Future income tax assets *(Note 5)*	35	21
Other	8	16
	1,189	973
Fixed assets *(Note 6)*:		
Fixed assets in service	19,767	18,407
Less: Accumulated depreciation	7,247	6,815
	12,520	11,592
Construction in progress	1,402	1,256
Future use land, components and spares	139	150
	14,061	12,998
Other long-term assets:		
Regulatory assets *(Notes 8 and 22)*	1,013	858
Deferred pension asset *(Note 12)*	460	424
Long-term investment *(Note 9)*	249	-
Intangible assets (net of accumulated amortization) *(Notes 2 and 7)*	189	218
Goodwill	133	133
Future income tax assets *(Notes 2 and 5)*	19	18
Other	9	13
	2,072	1,664
Total assets	17,322	15,635

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2010**	**2009**
Liabilities		
Current liabilities:		
Bank indebtedness	-	26
Accounts payable and accrued charges *(Notes 13 and 16)*	884	800
Regulatory liabilities *(Note 8)*	72	100
Accrued interest	84	74
Short-term notes payable	-	55
Long-term debt payable within one year *(Note 9)*	500	600
	1,540	1,655
Long-term debt *(Note 9)*	7,278	6,281
Other long-term liabilities:		
Employee future benefits other than pension *(Note 12)*	980	940
Regulatory liabilities *(Notes 8 and 22)*	540	489
Future income tax liabilities *(Notes 5 and 22)*	693	533
Environmental liabilities *(Note 13)*	287	303
Asset retirement obligations *(Note 14)*	11	-
Long-term accounts payable and other liabilities	12	16
	2,523	2,281
Total liabilities	11,341	10,217
Contingencies and commitments *(Notes 18 and 19)*		
Shareholder's equity *(Note 15)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	2,354	1,791
Accumulated other comprehensive income	(10)	(10)
Total shareholder's equity	5,981	5,418
Total liabilities and shareholder's equity	17,322	15,635

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

James Arnett
Chair

Michael J. Mueller
Chair, Audit and Finance Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**
Operating activities		
Net income	591	470
Environmental expenditures	(17)	(9)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	526	487
Regulatory asset and liability accounts	(10)	(34)
Future income taxes	(8)	16
Asset retirement obligation	4	-
Other	1	-
	1,087	930
Changes in non-cash balances related to operations *(Note 17)*	77	(38)
Net cash from operating activities	1,164	892
Financing activities		
Long-term debt issued	1,500	1,150
Long-term debt retired	(600)	(400)
Short-term notes payable	(55)	55
Dividends paid	(28)	(188)
Other	-	2
Net cash from financing activities	817	619
Investing activities		
Capital expenditures		
Fixed assets	(1,557)	(1,473)
Intangible assets	(13)	(93)
	(1,570)	(1,566)
Long-term investments	(250)	-
Other assets	37	13
Net cash used in investing activities	(1,783)	(1,553)
Net change in cash and cash equivalents	198	(42)
Cash and cash equivalents, January 1	(26)	16
Cash and cash equivalents, December 31 *(Note 17)*	172	(26)

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Lake Erie Link Management Inc. and Hydro One Lake Erie Link Company Inc.

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate-setting

The rates of the Company's electricity Transmission and Distribution Businesses are subject to regulation by the OEB.

Transmission

On August 16, 2007, the OEB issued its decision in respect of Hydro One Networks' 2007 and 2008 transmission rate application. As part of that decision the OEB approved the disposition of export and wheeling fees liability and the transmission market-ready regulatory asset, which was factored into rates and refunded to customers over the four-year period ending December 31, 2010.

On May 30, 2008, Hydro One Networks submitted an application to the OEB to adjust Uniform Transmission Rates (UTRs) effective January 1, 2009. On August 28, 2008, the OEB approved the application allowing Hydro One Networks to recover revenues consistent with the OEB-approved 2008 revenue requirement which reflected the full repayment to customers of the amounts recorded in the Earnings Sharing Mechanism and the Revenue Difference Deferral Account at the end of 2008.

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

On May 19, 2010 Hydro One Networks submitted an application for 2011 and 2012 transmission rates in continued support of its aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the Green Energy Act (GEA). This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012.

On December 23, 2010, the OEB issued its decision effective January 1, 2011 which resulted in revenue requirements of $1,346 million for 2011 and $1,658 million for 2012. The change in our 2012 revenue requirement resulted in a higher revenue requirement than originally submitted due to the OEB directing Hydro One to adopt IFRS accounting for overheads capitalized resulting in a $200 million increase in 2012.

Distribution

On December 18, 2008, the OEB issued a decision approving substantially all work program expenditures effective May 1, 2008, for implementation on February 1, 2009. The OEB also approved recovery of our smart meter expenditures made prior to the end of 2007. The decision approved the establishment of the revenue recovery account (Rider 4) to record the revenue differential between existing distribution rates and new rates. Rider 4 is being recovered over a 27-month period commencing February 1, 2009 and ending April 30, 2011.

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

In 2009, Hydro One Networks filed a cost-of-service application with the OEB for 2010 and 2011 distribution rates reflecting the Company's plan to invest in its network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability of system growth requirements; and investments required by the GEA. The application sought OEB approval of revenue requirements of approximately $1,150 million and $1,264 million for 2010 and 2011, respectively.

On April 9, 2010, the OEB released its decision approving revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 to support the necessary work programs, the implementation of the GEA and the installation of smart meters. The OEB also approved certain distribution-related deferral account balances sought by Hydro One Networks in its application including retail settlement variance accounts, regulatory asset recovery account I, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a single regulatory account (Rider 6) to be recovered over an 18-month period from May 1, 2010 to December 31, 2011.

On November 1, 2007, Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's second-generation IRM policy which incorporates an OEB-approved formula that considers inflation and efficiency targets. On March 19, 2008, the OEB released its decision. The revised rates, including an amount of 67 cents per month per metered customer for smart meters, were approved with an implementation date of May 1, 2008.

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

On November 6, 2009, Hydro One Brampton filed an application for 2010 distribution rates on the basis of the OEB's second-generation IRM process. On April 13, 2010, the OEB released its decision regarding this rate application approving our submission on the basis of the OEB's cost-of-capital and second-generation IRM policies. The revised rates had an implementation date of May 1, 2010.

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

On November 4, 2009, Hydro One Remote Communities filed an application for 2010 distribution rates under the OEB's third-generation IRM, seeking approval of an increase to basic rates for the distribution and generation of electricity effective May 1, 2010. The increase reflects the standard inflationary adjustments incorporated in the third-generation IRM applications. On April 14, 2010, the OEB issued a decision regarding this rate application under the OEB's third-generation IRM policies. The revised rates were approved for implementation on May 1, 2010.

Regulatory Accounting

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 8.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2010 amounted to $493 million (2009 - $434 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (*Corporations Tax Act* (Ontario), prior to 2009) as modified by the *Electricity Act, 1998*, and related regulations.

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

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

Adjustments to retained earnings were recorded on January 1, 2009 for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008 that are excluded from the rate-setting process.

Current Income Taxes

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

Future Income Taxes

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

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

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

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

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

Materials and Supplies

Materials and supplies represent consumables, spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering, overheads, depreciation on service equipment and the OEB-approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land; major components and spare parts; and capitalized development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity such as transmission lines; support structures; foundations; insulators; connecting hardware and grounding systems; and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and other minor fixed assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to land access rights.

Intangible Assets

Intangible assets represent computer applications software and other assets. These assets are capitalized at cost, which comprises materials, purchased software, labour and consulting, engineering, overheads and the OEB-approved allowance for funds used during construction applicable to capital construction activities within regulated businesses.

Construction and Development in Progress

Overhead costs, including shared corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on rate-regulated fixed assets under construction and intangible assets under development, based on the OEB's approved allowance for funds used during construction (2010 – 4.34%; 2009 – 5.89%).

Depreciation and Amortization

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

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

	Depreciation and amortization rates (%)	
	Range	Average
Transmission	1% - 3%	2%
Distribution	1% - 13%	2%
Communication	1% - 13%	5%
Administration and service	1% - 20%	9%

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

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of fixed assets that are normally retired is charged to accumulated depreciation or amortization, with no gain or loss reflected in current results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation or amortization expense. Depreciation expense also includes the costs incurred to remove fixed assets where no asset retirement obligation has been recorded.

The estimated service lives of fixed or intangible assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis consistent with their inclusion in electricity rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations. The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the Distribution Business segment.

Discounts and Premiums on Debt

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

Financial Instruments

Comprehensive Income

Comprehensive income is comprised of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on discontinued cash flow hedges and the change in fair value on existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the hedged debt.

Financial Assets and Liabilities

All financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the Consolidated Balance Sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period in which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Short-term investments	Held-to-maturity/Held-for-trading
Long-term investment	Held-to-maturity/Held-for-trading
Fixed-to-floating interest rate swaps	Not classified
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Accounts payable	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (unless otherwise specified)	Other liabilities
MTN Series 14 Note	Not classified
$500 million of MTN Series 19 Note	Not classified

Short-term investments are generally classified as held-to-maturity; however, certain short-term investments are classified as held-for-trading when the Company has no intent to hold a pool of assets to their maturity. Documentation of the short-term investment classification is made on inception.

Where long-term debt is designated as part of a hedging relationship, as in the case of the MTN Series 14 Note and $500 million of the MTN Series 19 Note, the long-term debt, and related hedging instrument, are not classified.

All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

All derivative instruments, including embedded derivatives, are carried at fair value on the Consolidated Balance Sheet unless exempted from derivative treatment as a normal purchase and sale or when it is deemed that the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The gain or loss related to the ineffective portion, if any, is recorded in financing charges.

The Company does not engage in derivative trading or speculative activities.

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company formally documents the hedging relationship between the hedged item and the hedging instrument, its risk management objective for establishing the hedging relationship, the nature of the specific risk exposure being hedged, and the method for assessing effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedging items that are used are effective in offsetting changes in fair values or cash flows of the hedged items.

Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method.

Financial Instrument Disclosures

The fair market value of the Company's long-term debt is determined using the fair value hierarchy levels disclosed in Note 10.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

Hydro One records a liability for the estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyls (PCBs) contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recorded to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Asset Retirement Obligations

When required by force of law or regulation, Hydro One records an asset retirement obligation based on the present value of the estimated fair value expenditures to remove certain assets and mitigate related sites. Where the Company anticipates that the related expenditures will be recoverable in future rates, a corresponding amount is capitalized as a cost of the related fixed assets. Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligation currently exists. If, at some future date, a particular facility is shown not to meet the perpetuity criterion, it will be reviewed to determine whether a measurable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

Emerging Accounting Changes

International Financial Reporting Standards (IFRS)

On February 13, 2008 the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the Company will apply IFRS to its financial statements ending December 31, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes. The Company continues to assess the impact of conversion to IFRS on its results of operations.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**
Depreciation of fixed assets in service	456	418
Amortization of intangible assets	43	36
Fixed asset removal costs	57	50
Amortization of regulatory and other assets	27	33
	583	537

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**
Interest on long-term debt payable	409	369
Less: Interest capitalized on construction and development in progress	(54)	(58)
Interest earned on investments	(3)	(1)
Other	(10)	(2)
	342	308

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

(Canadian dollars in millions)	**2010**	**2009**
Income before provision for PILs	647	516
Federal and Ontario statutory income tax rate	31.00%	33.00%
Provision for PILs at statutory rate	201	170
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(82)	(74)
Retail settlement variance accounts	-	4
Pension contributions in excess of pension expense	(18)	(15)
Overheads capitalized for accounting but deducted for tax purposes	(13)	(14)
Interest capitalized for accounting but deducted for tax purposes	(17)	(19)
Employee future benefits other than pension expense in excess of cash payments	3	1
Environmental expenditures	(5)	(3)
Other	(15)	(6)
Net temporary differences	(147)	(126)
Net permanent differences	2	2
Total income tax provision for PILs	56	46
Current income tax provision for PILs	64	30
Future income tax provision for PILs	(8)	16
Total income tax provision for PILs	56	46
Effective income tax rate	8.66%	8.91%

The provision for payments in lieu of current income taxes of $64 million represents the amount payable to the OEFC with respect to current year earnings. The outstanding balance due to the OEFC at December 31, 2010 is $17 million (2009 - $6 million recoverable).

The payments in lieu of future income taxes recoverable of $8 million reflects the decrease in the liability for payments in lieu of future income taxes that are not expected to be recovered from the Company's customers through future rates. The decrease in the liability for payments in lieu of future income taxes that is expected to be recovered from the Company's customers through future rates has resulted in a decrease in regulatory assets.

Future Income Tax Assets and Liabilities

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

December 31 (Canadian dollars in millions)	**2010**	**2009**
Future income tax assets		
Depreciation and amortization in excess of capital cost allowance	9	6
Employee future benefits other than pension expense in excess of cash payments	5	4
Retail settlement variance accounts	-	3
Environmental expenditures	3	3
Other	5	3
Total future income tax assets	22	19
Less: current portion	3	1
	19	18

December 31 (Canadian dollars in millions)	2010	2009
Future income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(1,004)	(825)
Employee future benefits other than pension expense in excess of cash payments	337	314
Environmental expenditures	76	82
Transmission and Distribution amounts received but not recognized for accounting purposes	(69)	(68)
Goodwill	(17)	(18)
Retail settlement variance accounts	5	5
Other	11	(3)
Total future income tax liabilities	(661)	(513)
Less: current portion	32	20
	(693)	(533)

As at December 31, 2010, payments in lieu of future income tax assets of $574 thousand (2009 – $461 thousand), based on substantively enacted income tax rates and laws, have not been recorded, as it is more likely than not that the assets will not be realized in the future.

6. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets	Accumulated Depreciation	Construction in Progress	Total
2010				
Transmission	10,204	3,626	1,070	7,648
Distribution	7,230	2,556	262	4,936
Communication	892	426	37	503
Administration and service	1,089	554	33	568
Easements	491	85	-	406
	19,906	7,247	1,402	14,061
2009				
Transmission	9,485	3,455	956	6,986
Distribution	6,773	2,392	220	4,601
Communication	806	376	54	484
Administration and service	1,007	510	26	523
Easements	486	82	-	404
	18,557	6,815	1,256	12,998

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $54 million in 2010 (2009 - $55 million).

7. INTANGIBLE ASSETS

December 31 (Canadian dollars in millions)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2010				
Computer applications software	395	209	1	187
Other assets	5	3	-	2
	400	212	1	189
2009				
Computer applications software	379	166	3	216
Other assets	5	3	-	2
	384	169	3	218

Financing costs are capitalized on intangible assets under development, including allowance for funds used during construction on regulated assets, and were $nil in 2010 (2009 - $3 million).

8. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (Canadian dollars in millions)	**2010**	**2009**
Regulatory assets:		
Regulatory future income tax asset	674	523
Environmental	309	327
Pension cost variance account	27	7
Rider 2 (Regulatory asset recovery account II)	11	19
Rural and remote rate protection variance account	7	24
Long-term project development cost account	7	2
Rider 4 (Revenue Recovery Account)	5	18
Other	15	10
Total regulatory assets	1,055	930
Less: current portion	42	72
	1,013	858

Regulatory liabilities:		
Deferred pension	460	424
External revenue variance account	29	12
Regulatory future income tax liability	30	32
Retail settlement variance accounts	22	-
Rider 3 (regulatory liability refund account)	19	49
Rider 6	19	31
Rider 8	9	-
Hydro One Brampton rider	6	9
Export and wheeling fees	3	15
Other	15	17
Total regulatory liabilities	612	589
Less: current portion	72	100
	540	489

Regulatory Assets

Regulatory Future Income Tax Asset and Liability

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result the provision for PILs would have been higher by approximately $104 million (2009 - $127 million) including the impact of a change in substantively enacted tax rates.

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 13). Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2010, this regulatory asset decreased by $15 million (2009 – increased by $30 million) to reflect related changes in the Company's PCB liability and decreased by $1 million (2009 – increased by $40 million) for a change in the land assessment and remediation (LAR) liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been lower by $16 million (2009 - higher by $70 million). In addition, amortization expense in 2010 would have been lower by $17 million (2009 - $9 million) and financing charges would have been higher by $15 million (2009 - $13 million).

Pension Cost Variance Account

The pension cost variance account was established for Hydro One Networks' Transmission and Distribution Businesses to track the difference between the actual pension costs incurred by the Company and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension costs paid compared to OEB-approved amounts. On May 28, 2009, the OEB announced its decision regarding the Company's rate application in respect of the Transmission Business of Hydro One Networks for 2009 and 2010 rates. As part of this decision, the OEB approved recovery of the proposed balance in this account plus accrued interest for recovery over 18 months ending December 31, 2010. In the December 23, 2010 decision on 2011 and 2012 transmission rates, the OEB approved the December 31, 2009 balance, including accrued interest, to be recovered over a one-year period from January 1, 2011 to December 31, 2011. In the absence of rate-regulated accounting, revenue would have been lower by $20 million in 2010 (2009 - $7 million).

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

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate-regulated accounting, amortization expense in 2010 would have been lower by $8 million (2009 - $23 million). In addition, related financing charges would have remained the same in both years.

Rural and Remote Rate Protection Variance Account (RRRP)

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

Long-term Project Development Cost Account

On May 28, 2009 the OEB approved the creation of a deferral account to record Hydro One's costs of preliminary work to advance certain transmission projects identified in its 2009 and 2010 transmission rate application. On

March 25, 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 21, 2009 request from the Government of Ontario. In its December 23, 2010 decision, the OEB approved the recovery of the December 31, 2009 balance, including accrued interest, over a one-year period from January 1, 2010 to December 31, 2011. The Company anticipates that it will seek recovery for the remaining balance in its next transmission rate application. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been higher by $5 million (2009 - $2 million).

Rider 4 or Revenue Recovery Account

On December 18, 2008, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. The approved rates were effective May 1, 2008 with an implementation date of February 1, 2009. The OEB approved the establishment of Rider 4 to record the revenue differential between existing distribution rates and the new rates. The OEB ordered that the approved revenue requirement be retroactively recovered, through a rate rider, over a period of 27 months commencing February 1, 2009 and ending April 30, 2011.

Regulatory Liabilities

Deferred Pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid into the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate-regulated accounting, operating, maintenance and administration expense would have been lower by $22 million (2009 - higher by $9 million).

External Revenue Variance Account

In its May 28, 2009 decision, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use and external revenue from station maintenance and engineering and construction work. These revenue sources are an offset to the Company's revenue requirement, and as such, the OEB requested the establishment of new variance accounts to capture any difference between the approved forecast and actual revenues from these sources of external revenue. The balance reflects the excess of external revenue compared to the OEB-approved forecast. The OEB's December 23, 2010 decision approved the disposition of the December 31, 2009 balance, including accrued interest, over a one-year period from January 1, 2010 to December 31, 2011.

Retail Settlement Variance Accounts (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 18, 2008 decision allowed for the disposition of RSVA accumulated since May 1, 2006 through to April 30, 2008, inclusive of interest, within the Regulatory Liability Refund Account (RLRA). Hydro One Networks accumulated a net liability in its RSVA from May 1, 2008 to December 31, 2009. On April 9, 2010, the OEB announced its decision regarding Hydro One Networks' distribution rate application which included the allowance to dispose of the RSVA accumulated during that period, inclusive of interest, within Rider 6. Hydro One Networks has accumulated a net liability in its RSVA account since December 31, 2009.

RLRA

The OEB's December 18, 2008 decision approved certain distribution-related deferral account balances sought by Hydro One in its application including RSVA amounts, deferred tax changes, OEB costs and smart meters. Amounts approved for recovery represented balances incurred prior to April 30, 2008, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered over a 27-month period from February 1, 2009 to April 30, 2011.

Rider 6

As part of the April 9, 2010 decision, the OEB approved certain distribution-related deferral account balances sought by Hydro One in its application including retail settlement variance accounts, regulatory asset recovery account I, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered over an 18-month period from May 1, 2010 to December 31, 2011.

Rider 8

As part of the April 9, 2010 decision, the OEB also requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and actual recoveries received.

Hydro One Brampton Rider

On April 13, 2010, the OEB issued a decision regarding the 2010 distribution rates of Hydro One Brampton. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVA, sought by Hydro One Brampton in its application. The OEB ordered that the approved balances be aggregated into a single regulatory account to be disposed of over a two-year period from May 1, 2010 to April 30, 2012.

Export and Wheeling Fees

Consistent with the IESO's Market Rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of these export and wheeling fees, plus interest, were taken into consideration in the revenue requirement of Hydro One Networks' Transmission Business as part of the Company's transmission rate application filed with the OEB in September 2006. On August 16, 2007, the OEB issued its decision in respect of the Company's transmission rate application and approved final amounts and disposition treatments for the export and wheeling fees. The export and wheeling fees were factored into rates over a four-year period ending December 31, 2010.

9. DEBT

December 31 (Canadian dollars in millions)	**2010**	**2009**
Long-term debt:		
7.15% debentures due 2010	-	400
3.89% notes due 2010	-	200
4.08% notes due 2011 [1]	250	250
6.40% notes due 2011	250	250
5.77% notes due 2012	600	600
5.00% notes due 2013	600	600
3.13% notes due 2014 [1]	750	250
2.95% notes due 2015	250	-
4.64% notes due 2016	450	450
5.18% notes due 2017	600	600
4.40% notes due 2020	300	-
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	385	385
5.36% notes due 2036	600	600
4.89% notes due 2037	400	400
6.03% notes due 2039	300	300
5.49% notes due 2040	500	300
6.59% notes due 2043	315	315
5.00% notes due 2046	325	75
	7,775	6,875
Add: Unrealized hedged loss [1]	8	11
Less: Long-term debt payable within one year	(500)	(600)
Net unamortized premiums	27	24
Unamortized debt issuance costs	(32)	(29)
Long-term debt	7,278	6,281

[1] The unrealized hedged loss relates to the MTN Series 14 Note, and $500 million of the MTN Series 19 Note issued in January of 2010, which are accounted for as fair value hedges. The unrealized hedged loss is offset by the $8 million (2009 - $11 million) unrealized gain on the related fixed-to-floating interest rate swap agreements.

Short-term debt represents promissory notes pursuant to the Company's Commercial Paper Program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2010, the notes had a weighted average interest rate of 0.05%.

Hydro One has a $1,250 million committed and unused revolving standby credit facility with a syndicate of banks maturing in June 2013. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program. In addition, the Company holds $250 million of Province of Ontario Floating Rate Notes.

The Company issues notes for long-term financing under the Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million, of which $1,250 million was remaining and available as at December 31, 2010.

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

10. CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying value of financial instruments as at December 31, 2010 is as follows:

(Canadian dollars in millions)	**Derivatives Used for Hedging**	**Other Financial Instruments Used for Hedging**	**Held-for-Trading**	**Loans and Receivables**	**Other Financial Liabilities**
Financial Assets					
Cash	-	-	33	-	-
Accounts receivable	-	-	-	911	-
Short-term investments	-	-	139	-	-
Long-term investment	-	-	249	-	-
Other assets	8	-	-	1	-
Financial Liabilities					
Accounts payable and accrued charges[1]	-	-	-	-	861
Long-term debt	-	758	-	-	7,020

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

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, provided in the table below, is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturities. The fair value measurement of long-term debt is categorized as level 1 as the inputs used reflect quoted prices in an active market.

December 31 (Canadian dollars in millions)	**2010**		**2009**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	7,775	8,555	6,875	7,302

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the MTN Series 14 Note and $500 million of the MTN Series 19 Note, which are designated as part of hedging relationships.

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

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with the Company's capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency denominated debt which would be hedged back to Canadian dollars consistent with Hydro One's risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's Distribution and Transmission Businesses is derived using a formulaic approach which is based on the forecast for long-term Government of Canada bond yields and the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in determining the Company's rate of return would reduce its Transmission Business' results of operations by approximately $16 million and its Distribution Business' results of operations by approximately $10 million.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2010, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any individual customer. As at December 31, 2010, there were no significant balances of accounts receivable due from any single customer.

In the year, the Company's provision for bad debts remained unchanged at $25 million (2009 - $25 million). Minor adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2010, approximately 3% of the Company's accounts receivable were aged more than 60 days.

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

The Company uses derivative financial instruments to manage interest rate risk. Hydro One may enter into derivative agreements such as forward-starting pay fixed-interest rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. No such agreements were outstanding as at December 31, 2010.

Derivative financial instruments result in exposure to credit risk since there is a risk of counter-party default. As at December 31, 2010, the derivative instruments held by Hydro One include a $250 million fixed-to-floating interest rate swap agreement to convert the 4.08% coupon note maturing March 3, 2011 into a three-month variable rate debt and two $250 million fixed-to-floating interest rate swap agreements to convert $500 million of the 3.13% coupon note maturing November 19, 2014 into a three-month variable rate debt. The counter-party credit risk exposure on the fair value of the three interest rate swap contracts is $11 million as at December 31, 2010.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and cash equivalents on hand, funds from operations, the Company's Commercial Paper Program, under which it is authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holdings of Province of Ontario Floating Rate Notes. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks maturing June 1, 2013 and the holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

As at December 31, 2010, accounts payable and accrued charges in the amount of $861 million are expected to be settled in cash at their carrying amounts within the next year. Long-term debt maturing over the next twelve months is $500 million. Interest payments over the next 12 months on the Company's outstanding long-term debt amount to $405 million.

As at December 31, 2010, Hydro One has issued long-term debt in the amount of $7,775 million and the Company is required to make interest payments in the amount of $6,599 million. Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table.

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Interest Payments *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	500	405	5.2
2 years	600	383	5.8
3 years	600	349	5.0
4 years	750	319	3.1
5 years	250	295	3.0
	2,700	1,751	4.5
6 – 10 years	1,350	1,246	4.8
Over 10 years	3,725	3,602	6.0
	7,775	6,599	5.3

11. CAPITAL MANAGEMENT

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

The Company considers its capital structure to consist of shareholder's equity, short-term notes payable, long-term debt and cash and cash equivalents. The Company's capital structure as at December 31, 2010 and December 31, 2009 was as follows:

(Canadian dollars in millions)	**2010**	**2009**
Short-term notes payable	-	55
Long-term debt payable within one year	500	600
Less: Cash and cash equivalents	33	(26)
	467	681
Long-term debt	7,278	6,281
Preferred Shares	323	323
Common Shares	3,314	3,314
Retained Earnings	2,354	1,791
	5,991	5,428
Total Capital	13,736	12,390

For the purposes of this table and the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash" and "bank indebtedness."

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2010, Hydro One is in compliance with all of these covenants and limitations.

12. EMPLOYEE FUTURE BENEFITS

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2010 and 2009 was as follows:

	% of Plan Assets	
December 31	**2010**	**2009**
Equity securities	63.5	63.3
Debt securities	30.7	32.9
Other	5.8	3.8
	100.0	100.0

Supplementary Information

The Hydro One pension plan holds $14 million of Hydro One Inc. corporate bonds (2009 - $9 million) and holds debt securities of the Province of $70 million at December 31, 2010 (2009 - $88 million).

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed with the Financial Services Commission of Ontario (FSCO) in September 2010, effective for December 31, 2009, the Company contributed $193 million to its pension plan in respect of 2010 (2009 - $112 million), $145 million of which is required to satisfy minimum funding requirements. The Company made an additional payment of $48 million in December 2010. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2012 will be based on an actuarial valuation effective December 31, 2012 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2010, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans, was $233 million (2009 - $155 million).

Year ended December 31 (Canadian dollars in millions)	Pension 2010	Pension 2009	Employee Future Benefits other than Pension 2010	Employee Future Benefits other than Pension 2009
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	4,566	4,007	1,004	874
Current service cost	94	73	24	19
Interest cost	294	286	65	63
Reciprocal transfers	4	-	-	-
Benefits paid	(262)	(270)	(42)	(43)
Net actuarial loss (gain)	300	470	127	91
Accrued benefit obligation, December 31	4,996	4,566	1,178	1,004
Change in plan assets				
Fair value of plan assets, January 1	4,336	3,836	-	-
Actual return on plan assets	421	642	-	-
Reciprocal transfers	4	6	-	-
Benefits paid	(262)	(270)	-	-
Employer's contributions[1]	191	112	-	-
Employees' contributions	24	21	-	-
Administrative expenses	(15)	(11)	-	-
Fair value of plan assets, December 31	4,699	4,336	-	-
Funded status				
Unfunded benefit obligation	(297)	(230)	(1,178)	(1,004)
Unamortized net actuarial losses (gains)	746	640	144	10
Unamortized past service costs	11	14	11	14
Deferred pension asset (accrued benefit liability)	460	424	(1,023)	(980)
Less: Current portion	-	-	43	40
Deferred pension asset (long-term liability)	460	424	(980)	(940)

[1] In January 2011, the Company made a contribution of $13 million in respect of 2010 (2010 - $10 million in respect of 2009).

Year ended December 31 (Canadian dollars in millions)	Pension 2010	Pension 2009	Employee Future Benefits Other Than Pension 2010	Employee Future Benefits Other Than Pension 2009
Components of net periodic benefit cost				
Current service cost, net of employee contributions	70	52	24	19
Interest cost	294	286	65	63
Actual return on plan assets net of expenses	(406)	(631)	-	-
Actuarial loss (gain)	300	470	127	91
Other	(1)	(1)	-	-
Costs arising in the period	257	176	216	173
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	129	359	-	-
Actuarial (gain) loss	(236)	(410)	(134)	(101)
Plan amendments	4	4	4	4
Net periodic benefit cost	154	129	86	76
Charged to results of operations[2]	134	68	51	46
Effect of a 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	185	141
Service cost and interest cost	-	-	15	13
Effect of a 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	(146)	(113)
Service cost and interest cost	-	-	(12)	(10)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	6.50%	7.25%	-	-
Weighted average discount rate	6.50%	7.25%	6.50%	7.25%
Rate of compensation scale escalation (without merit)	2.50%	2.75%	2.50%	2.75%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Average remaining service life of employees *(years)*	10	10	11	11
Rate of increase in health care cost trend[3]	-	-	4.81%	4.81%
For accrued benefit obligation, December 31:				
Weighted average discount rate	5.75%	6.50%	5.75%	6.50%
Rate of compensation scale escalation (without merit)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trend[4]	-	-	4.86%	4.81%

[2] The Company follows the cash basis of accounting. During 2010, pension costs of $191 million (2009 - $113 million) were attributed to labour, of which $134 million (2009 - $68 million) was charged to operations and $57 million (2009 - $45 million) was capitalized as part of the cost of fixed assets.

[3] 8.57% in 2010 grading down to 4.81% per annum in and after 2029 (2009 – 8.81% in 2009 grading down to 4.81% per annum in and after 2029).

[4] 8.31% in 2011 grading down to 4.86% per annum in and after 2029 (2009 – 8.57% in 2010 grading down to 4.81% per annum in and after 2029).

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	Polychlorinated Biphenyls (PCB)	Land Assessment and Remediation (LAR)	Total
2010			
Opening balance, January 1	262	65	327
Interest accretion	13	2	15
Expenditures	(9)	(8)	(17)
Revaluation adjustment	(15)	(1)	(16)
Ending balance, December 31	251	58	309
Less: Current portion	(15)	(7)	(22)
	236	51	287
2009			
Opening balance, January 1	225	28	253
Interest accretion	12	1	13
Expenditures	(4)	(5)	(9)
Revaluation adjustment	29	41	70
Ending balance, December 31	262	65	327
Less: Current portion	(14)	(10)	(24)
	248	55	303

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2010 and in total thereafter are as follows: 2011 - $22 million; 2012 - $23 million; 2013 - $34 million; 2014 - $40 million; 2015 - $33 million and thereafter - $217 million. Of the total estimated future expenditures, $308 million relate to PCB (2009 - $320 million) and $61 million to LAR (2009 - $69 million).

Consistent with its accounting policy for environmental costs, Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment and for the assessment and remediation of chemically-contaminated lands. The Company's recorded liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, for the PCB program, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

PCBs

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on criteria including type of equipment, in-use status and PCB-contamination thresholds. All PCBs in concentrations of 500 parts per million (ppm) or more, except for specified equipment, had to be disposed of by the end of 2009. However, in 2009, Hydro One sought and received an extension until 2014 for the removal of PCBs from certain station equipment that could potentially be contaminated in excess of this threshold. Under the regulations, PCBs in equipment in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts must be disposed of by the end of 2025.

Management judges that the Company currently has very few PCB-contaminated assets in excess of 500 ppm. Priority will be given to targeting inspection and testing work toward identifying and removing PCBs in assets that must be compliant by 2014. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution and transmission station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retrofilling with replacement oil that is less than 2 ppm.

Management's best estimate of the total estimated future expenditures to comply with PCB regulations is about $308 million. These expenditures are expected to be incurred over the period from 2011 to 2025. As a result of its most recent cost estimate to comply with existing PCB regulations, the Company reduced its December 31, 2010 PCB liability by approximately $15 million compared to September 30, 2010.

LAR

As part of its annual review of environmental liabilities, the Company also reviewed its liability for LAR. As a result of this review, the Company reduced its December 31, 2010 liability by approximately $1 million compared to September 30, 2010. The Company's best estimate of the total future expenditures to complete its LAR program is about $61 million.

14. ASSET RETIREMENT OBLIGATIONS

Consistent with the Company's accounting policy for asset retirement obligations, Hydro One records a liability for the present value of the estimated future expenditures associated with the retirement of tangible long-lived assets that the Company is legally required to remove. A corresponding amount is recorded as an asset retirement cost that is capitalized as part of the carrying amount of the related fixed asset.

There are uncertainties in estimating future expenditures due to potential external events such as changing legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required removal and remediation work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3% to 5%, depending on the appropriate rate for the period when expenditures are expected to be incurred.

Hydro One has recorded a liability for the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The Company's liability is based on management's best estimate of the present value of the estimated future expenditures to comply with existing regulations. During the year, the Company completed a study with the aid of an expert external consultant to estimate the future expenditures required to remove asbestos prior to facility demolition. The Company has recorded a $7 million liability in respect of this obligation as at December 31, 2010 based on the net present value of the Company's best estimate of the total future expenditures of $18 million to complete its asbestos removal activities.

Hydro One has also recorded a $4 million asset retirement obligation related to the decommissioning and removal of its switching station located at Ontario Power Generation's Abitibi Canyon Generating Station.

15. SHARE CAPITAL

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2010, preferred dividends in the amount of $18 million (2009 - $18 million) and common dividends in the amount of $10 million (2009 - $170 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year.

16. RELATED PARTY TRANSACTIONS

The Province, OEFC, IESO, Ontario Power Authority (OPA) and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2010 includes $1,277 million (2009 - $1,121 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2010 includes $127 million (2009 - $127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2010 includes $28 million (2009 - $31 million) related to these services.

In 2010, Hydro One purchased power in the amount of $2,361 million (2009 - $2,265 million) from the IESO administered electricity market, $19 million (2009 - $19 million) from OPG and $13 million (2009 - $11 million) from OEFC.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2010, Hydro One incurred $11 million (2009 - $10 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $14 million (2009 - $13 million), primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $2 million in each of 2010 and 2009.

The OPA funds substantially all of our Conservation Demand Management (CDM) programs. The funding includes program costs, incentives, management fees and bonuses. In 2010, Hydro One received $36 million from the OPA in respect of the CDM programs (2009 - $23 million) and had a net accounts receivable of $1 million in both 2010 and 2009.

The provision for payments in lieu of corporate income taxes, property taxes and capital taxes was paid or payable to the OEFC and dividends were paid or payable to the Province.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	**2010**	**2009**
Accounts receivable	111	108
Accounts payable and accrued charges	(283)	(254)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $222 million (2009 - $211 million).

17. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash", "short-term investments" and "bank indebtedness." The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**
Accounts receivable increase	(68)	(89)
Materials and supplies increase	-	(2)
Accounts payable and accrued charges increase	87	-
Accrued interest increase	10	10
Long-term accounts payable and other liabilities (decrease) increase	(3)	4
Employee future benefits other than pension increase	40	32
Other	11	7
	77	(38)

Supplementary information:		
Interest paid	409	361
Payments in lieu of corporate income taxes	48	77

18. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Superior Court of Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and our Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The Red Rock First Nation Band commenced a similar claim on September 7, 2001 against the same parties. In 2004, the various claims were consolidated. These actions sought declaratory relief, injunctive relief and damages in an unspecified amount. The claims arose out of flooding activities of Ontario Hydro and the alleged effects of flooding on lands in which the two First Nations claim an interest. In May 2009, all parties entered into an agreement to dismiss all actions against Hydro One on a without costs basis. On July 27, 2010, by court order, the consolidated action and the cross claim of the Attorney General of Canada against Hydro One were dismissed without costs.

Transfer of Assets

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the $761,500 that we paid to these Indian bands and bodies in 2010. If we cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

19. COMMITMENTS

Agreement with Inergi

Effective March 1, 2002, Inergi LP (Inergi) (a wholly owned subsidiary of Cap Gemini Canada Inc.) began providing services to Hydro One. On May 1, 2010, consistent with the terms of the contract, the Company extended the Master Services Agreement with Inergi for a further three-year period to expire on February 28, 2015. As a result of this agreement, Hydro One receives from Inergi a range of services including business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. Inergi billing for these services has ranged between $93 million and $130 million per year and is subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2010, and in total thereafter are as follows: 2011 - $143 million; 2012 - $139 million; 2013 - $135 million; 2014 - $130 million; 2015 - $22 million; and thereafter - $nil. The agreement expires on February 28, 2015.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2010 and December 31, 2009, the Company provided prudential support to the IESO on behalf of Hydro One Networks and Hydro One Brampton using only parental guarantees of $325 million. Prudential support at December 31, 2010 and December 31, 2009 was also provided on behalf of two distributors using guarantees of $660 thousand. The IESO could draw on these guarantees if these subsidiaries or distributors fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any bank letters of credit plus the nominal amount of the corporate guarantee. If Hydro One's highest long-term credit rating deteriorated to below the "Aa" category, the Company would be required to resume providing letters of credit as prudential support.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2010, Hydro One had bank letters of credit of $113 million (2009 - $107 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2010, and in total thereafter are as follows: 2011 - $5 million; 2012 - $8 million; 2013 - $6 million; 2014 - $7 million; 2015 - $2 million; and thereafter - $25 million.

20. SEGMENT REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- The "other" segment, the operations of which primarily consist of those of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2010				
Segment profit				
Revenues	1,307	3,754	63	5,124
Purchased power	-	2,474	-	2,474
Operation, maintenance and administration	416	602	60	1,078
Depreciation and amortization	273	300	10	583
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	618	378	(7)	989
Financing charges				342
Income before provision for payments in lieu of corporate income taxes				647
Capital expenditures	936	629	5	1,570

Year ended December 31 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2009				
Segment profit				
Revenues	1,147	3,534	63	4,744
Purchased power	-	2,326	-	2,326
Operation, maintenance and administration	438	564	55	1,057
Depreciation and amortization	240	287	10	537
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	469	357	(2)	824
Financing charges				308
Income before provision for payments in lieu of corporate income taxes				516
Capital expenditures	918	643	5	1,566

December 31 (Canadian dollars in millions)	**2010**	**2009**
Total assets		
Transmission	9,805	8,993
Distribution	6,908	6,481
Other	609	161
	17,322	15,635

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

21. SUBSEQUENT EVENTS

On February 2, 2011, the Power Workers' Union (PWU) requested that the Ministry of Labour appoint a Conciliation Officer to assist Hydro One and the PWU in finalizing a new collective agreement. Negotiations on the new agreement began on January 10, 2011.

On January 24, 2011, Hydro One issued notes under the Company's MTN Program. The issue consisted of $50 million floating-rate notes with a maturity date of July 24, 2015.

On January 19, 2011, Hydro One issued $250 million in notes under the Company's MTN Program. The issue has an additional offering of 2.95% notes maturing on September 11, 2015, originally issued on September 13, 2010. The total amount outstanding for this issue is now $500 million.

On January 19, 2011, Hydro One entered into two $125 million notional principal amount fixed-to-floating interest rate swaps to convert $250 million of Hydro One's 2.95% coupon note maturing September 11, 2015, into three-month variable rate debt.

On January 17, 2011, the PWU made an appeal to the Divisional Court of the Supreme Court of Canada under the *Ontario Energy Board Act, 1998* in regard to the OEB's December 23, 2010 decision approving Hydro One Networks' transmission rates for 2011 and 2012. The PWU submitted the appeal on the grounds that the decision failed to identify operations, maintenance and administration costs that the OEB considers imprudent and were therefore omitted in the calculation of the approved revenue requirement. The PWU is requesting that the OEB's determination regarding the revenue requirement and related rates be set aside and that the matter be remitted to a differently constituted panel of the OEB for a new hearing with respect to these issues. The appeal is not anticipated to impact upon the collection of the new 2011 transmission rates during the proceeding. The outcome of this appeal is not determinable at this time.

22. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2010 Consolidated Financial Statements.

In the third quarter, the Company changed the presentation of tax balances associated with certain temporary differences related to intangible assets and other regulatory account balances, to reflect how these balances will ultimately be settled. As a result, the Company reclassified the tax balances associated with these temporary differences, such that the amount of future income tax liabilities and the related net regulatory asset in the interim period balance sheet, and in the comparative December 31, 2009 balance sheet, have been reduced by $160 million. The change in presentation has no impact on revenue or operating cash flow.

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**	**2008**	**2007**	**2006**
Statement of operations data					
Revenues					
Transmission	1,307	1,147	1,212	1,242	1,245
Distribution	3,754	3,534	3,334	3,382	3,273
Other	63	63	51	31	27
	5,124	4,744	4,597	4,655	4,545
Costs					
Purchased power	2,474	2,326	2,181	2,240	2,221
Operation, maintenance and administration	1,078	1,057	965	995	880
Depreciation and amortization	583	537	548	521	515
	4,135	3,920	3,694	3,756	3,616
Income before financing charges and provision for payments in lieu of corporate income taxes	989	824	903	899	929
Financing charges	342	308	292	295	295
Income before provision for payments in lieu of corporate income taxes	647	516	611	604	634
Provision for payments in lieu of corporate income taxes	56	46	113	205	179
Net income	591	470	498	399	455
Basic and fully diluted earnings per common share *(Canadian dollars)*	5,727	4,528	4,797	3,809	4,366

December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	9,805	8,993	7,877	7,273	6,950
Distribution	6,908	6,481	5,873	5,407	5,161
Other	609	161	128	106	99
Total assets	17,322	15,635	13,878	12,786	12,210
Liabilities					
Current liabilities (including current portion of long-term debt)	1,540	1,655	1,300	1,452	1,194
Long-term debt	7,278	6,281	5,733	5,063	4,848
Other long-term liabilities	2,523	2,281	1,721	1,385	1,347
Shareholder’s equity					
Share capital	3,637	3,637	3,637	3,637	3,637
Retained earnings	2,354	1,791	1,497	1,258	1,184
Accumulated other comprehensive income	(10)	(10)	(10)	(9)	-
Total liabilities and shareholder’s equity	17,322	15,635	13,878	12,786	12,210

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS (continued)

Year ended December 31 (Canadian dollars in millions)	**2010**	**2009**	**2008**	**2007**	**2006**
Other financial data					
Capital expenditures					
Transmission	936	918	704	560	402
Distribution	629	643	570	511	417
Other	5	5	10	20	4
Total capital expenditures	1,570	1,566	1,284	1,091	823
Ratios					
Net asset coverage on long-term debt[1]	1.77	1.79	1.84	1.87	1.92
Earnings coverage ratio[2]	2.39	2.15	2.63	2.67	2.67
Operating statistics					
Transmission					
Units transmitted *(TWh)*[3]	142.2	139.2	148.7	152.2	151.1
Ontario 20-minute system peak demand *(MW)*[3]	25,145	24,477	24,231	25,809	27,056
Ontario 60-minute system peak demand *(MW)*[3]	25,075	24,380	24,195	25,737	27,005
Total transmission lines *(circuit-kilometres)*	28,951	28,924	29,039	28,915	28,600
Distribution					
Units distributed to Hydro One customers *(TWh)*[3]	29.1	28.9	29.9	30.2	29.0
Units distributed through Hydro One lines *(TWh)*[3,4]	42.5	43.5	44.7	45.7	44.7
Total distribution lines *(circuit-kilometres)*	123,552	123,528	123,260	122,933	122,460
Customers	1,345,177	1,333,920	1,325,745	1,311,714	1,293,396
Total regular employees	5,717	5,427	5,032	4,602	4,295

[1] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[2] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

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

[4] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

Ontario Energy Board (Board Staff) INTERROGATORY #23 List 1

Interrogatory

Ref: Exhibit D1/Tab1/Sch1 – Employee Future Benefits

Page 34 of Hydro One Inc.'s December 31, 2010 audited financial statements states:

> *Employee Future Benefits*
> In the absence of RRA, the continuation of accounting for expenditures related to employer-sponsored pension plans on a cash basis is not permissible. Regulatory assets and liabilities, representing the cumulative difference between our Company's pension contributions currently accounted for on a cash basis at the direction of the regulator, and the costs that would be recognized on an accrual basis under Canadian GAAP, would not meet the definition of assets or liabilities under IFRS and hence will require de-recognition at the IFRS transition date. We have assessed our options with respect to the recognition of accumulated, unamortized actuarial gains and losses associated with employment benefits. The possible alternatives to account for these pension and other employee benefit amounts include charging unamortized actuarial gains and losses immediately upon adoption under IFRS 1 or recognizing an adjustment to those amounts retrospectively to comply with IAS 19, *Employee Benefits* (IAS 19). In the absence of rate-regulated accounting, we intend to recognize a retrospective adjustment for these amounts under IAS 19, without the IFRS 1 exemption. The impact of adopting IAS 19 retrospectively at December 31, 2010 would have been a reduction to retained earnings of $319 million.

On page 34 of Hydro One Inc.'s December 31, 2010 audited financial statements, Hydro One stated that under IFRS it intended to recognize a retrospective adjustment for accumulated unamortized actuarial gains and losses associated with employee benefits. The impact of adopting IAS 19 retrospectively at December 31, 2010 would have been a reduction to retained earnings of $319 million.

i) Is an estimation of the amount of the impact of adopting IAS 19 retrospectively (or alternatively an estimation of charging unamortized actuarial gains and losses that would occur immediately upon adoption under IFRS 1), embedded in an amount included in the 2012 revenue requirement approved in EB-2010-0002?

ii) If this is the case, please explain and disclose the amount incorporated into the approved revenue requirement. If this is not the case, please explain.

iii) Please disclose any amount incorporated into the proposed 2012 revenue requirement, the Pension Cost Differential Account, or the Impact for US GAAP Account, for these types of costs that would occur under US GAAP.

iv) Please explain how the treatment of these costs would differ under US GAAP when compared to each of IFRS and Canadian GAAP.

Response

i) No.

ii) N/A.

iii) $ nil.

iv) Pensions

Under Canadian GAAP, Hydro One's pension expense is recognized on a cash basis based on pension contributions made by the Company. A regulatory asset or liability is recognized for the difference between the cash contributions made by the company and the actual pension cost incurred during the period on an accrual basis.

When US GAAP is adopted, pension expense will continue to be recognized under cash basis given the continuance of regulatory accounting.

Under current IFRS, the actual pension expense incurred on an accrual basis is recognized in net income since there is no regulatory accounting.

Employee Future Benefits Other Than Pension

Under Canadian GAAP, employee future benefits other than pension are recognized on an accrual basis.

Under both US GAAP and IFRS, employee future benefits other than pension will continue to be recognized under an accrual basis similar to CGAAP

Ontario Energy Board (Board Staff) INTERROGATORY #24 List 1

Interrogatory

Ref: Exhibit D1/Tab1/Sch1 – Employee Future Benefits

US GAAP requirements were effective for fiscal years beginning after December 15, 1988 for pensions and December 31, 1994 for employee future benefits other than pensions (OPEBs). The Securities and Exchange Commission provides an exemption for foreign registrants which permits them to adopt the US GAAP requirements as of a date prior to the first period US GAAP information is prepared.

a) Have Hydro One's external auditors confirmed that Hydro One qualifies for this Securities and Exchange Commission exemption and can use different effective dates than those articulated in US GAAP requirements?

b) If Hydro One qualifies for this Securities and Exchange Commission exemption, what date does Hydro One propose to adopt the US GAAP requirements for pensions and OPEBs? Please indicate the reasons for the choice of date(s).

Response

a) Yes. Hydro One would qualify for the exemption but in Hydro One's case it is not required.

b) Hydro One will continue to record its pension costs on a cash basis. Accrual accounting for OPEB costs was adopted upon the inception of Hydro One in 1999 and the one-time transition cost was recorded in a deferral account and recovered over a 10-year period ending 2008.

Ontario Energy Board (Board Staff) INTERROGATORY #25 List 1

Interrogatory

Ref: Exhibit C1/Tab1/Sch2 - Financial Instruments
Please explain the impact of the transition to US GAAP on Hydro One's financial instruments when compared to principles established under CGAAP and IFRS. Please provide estimated dollar impacts and describe Hydro One's proposed method of recovery of this impact.

Response

There is no transition impact related to existing financial instruments resulting from the transition from CGAAP to US GAAP.

London Property Management Association (LPMA) INTERROGATORY #1 List 1

Interrogatory

Ref: Exhibit A, Tab 3, Schedule 1

a) Other than the specific items listed in Section 2.0 of this schedule, is Hydro One requesting approval from the Board for any other changes or items? If yes, please specify.

b) Has Hydro One made any changes for which it is not seeking Board approval? If yes, please specify.

Response

a) No

b) No

London Property Management Association (LPMA) INTERROGATORY #2 List 1

Interrogatory

Ref: Exhibit C1, Tab 1, Schedule 2

a) Please confirm that the US GAAP adjustments shown in Table 1 are the exactly the same as the expected impact IFRS impact approved by the Board in EB-2010-0002.

b) What is Hydro One's basis for assuming that the reversing the IFRS impacts approved in EB-2010-0002 is equivalent to converting to US GAAP?

Response

a) So confirmed.

b) Based on extensive US GAAP conversion work completed to date by the Company with the support of its external auditor, Hydro One Transmission has determined that there are no major differences between CGAAP and US GAAP that have the potential to significantly impact its revenue requirement. Given this, the only adjustment required to restate the approved 2012 Transmission revenue requirement to a US GAAP basis would be to adjust revenue requirement for a capitalization policy adjustment related to overhead and indirect cost accounting differences between CGAAP/US GAAP and IFRS.

This $200 million adjustment mirrors that made by Hydro One Transmission in the rate order and approved by the OEB (see Exhibit C1, Tab 2, Schedules 1 & 2). The original revision to submitted revenue requirement was prepared in response to the Board's EB-2010-0002 decision not to allow the Company an exception allowing it to continue to capitalize certain overheads and indirect costs, previously capitalized under CGAAP, and not capitalizable under MIFRS.

London Property Management Association (LPMA) INTERROGATORY #3 List 1

Interrogatory

Ref: Exhibit D1, Tab 1, Schedule 1

a) With respect to the Impact for US GAAP Account for 2012 only requested by Hydro One, has Hydro One identified any other differences between Canadian and US GAAP other than the disclosure-related issues and the specialized areas of pensions and financial instruments noted? If yes please identify.

b) What is the estimated impact on the 2012 revenue requirement of the differences between Canadian and US GAAP related to the differences in pensions and financial instruments identified by Hydro One?

Response

a) Hydro One has not identified any significant accounting differences that are expected to impact the submitted 2012 revenue requirement. However, it is possible that minor differences will still be identified and the impact of these will be recorded in the account.

b) Hydro One Networks did not identify any impacts on revenue requirement in its CGAAP to US GAAP conversion work related to pensions and existing financial instruments.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #1 List 1

Interrogatory

Reference: Exhibit A, Tab 3, Schedule 1, Page 1

HONI's evidence indicates that in May 2011 it became known that there was an option for rate regulated entities to apply to its securities regulator for an exemption to permit use of United States Generally Accepted Accounting Principles (US GAAP) for the preparation of financial statements. On May 31, 2011, HONI wrote to the Board to advise the Board that it was evaluating the option of adopting US GAAP in lieu of Modified International Financial Reporting Standards (MIFRS) in 2012.

Please discuss the process by which HONI evaluated the option of adopting US GAAP and determined that a change in strategy to use an alternate financial reporting standard would be beneficial.

Response

Please refer to Exhibit I, Tab 1, Schedule 4.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #2 List 1

Interrogatory

Reference: Exhibit C, Tab 1, Schedule 1, Page 1

In the Addendum to the Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment, dated June 11, 2011, the Board stated that if a utility was filing a cost of service application following adoption of US GAAP, it would need to include the following information:

a) the eligibility of the utility under applicable securities legislation to report financial information using US GAAP;
b) the authorization by the appropriate Canadian Securities regulator authorizing the utility to use US GAAP for financial reporting purposes;
c) an explanation of the benefits and potential disadvantages of adoption of US GAAP rather than Modified International Financial Reporting Standards ("MIFRS")."

HONI's evidence at Exhibit C, Tab 1, Schedule 1 outlines how HONI meets the Board's above requirements and an explanation of the benefits is provided.

Please provide a detailed explanation of the potential disadvantages and consequences of adoption of US GAAP rather than MIFRS.

Response

Hydro One Networks has not identified any significant disadvantages to it or to its primary stakeholders in using US GAAP for rate setting purposes rather than MIFRS.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #3 List 1

Interrogatory

Reference: Exhibit B, Tab 1, Schedule 1

On July 21, 2011, HONI received approval from the Ontario Securities Commission to utilize US GAAP as the basis for preparing its financial statements for public securities filings beginning on or after January 1, 2012 but before January 1, 2015.

a) Please discuss the significance of January 1, 2015.

b) Please discuss HONI's plans in 2015 and beyond regarding the use of financial reporting standards.

c) Please comment on the potential confusion in the marketplace should HONI change its financial reporting standard in 2012 and 2015.

Response

a) See response to Exhibit I, Tab 1, Schedule 8.

b) See response to Exhibit I, Tab 1, Schedules 9 & 10.

c) Hydro One Networks does not expect to change its accounting standard again in 2015. If a change to IFRS becomes necessary, this should not present a significant issue in the market place as analysts and other stakeholder are well versed in understanding the issues in converting form CGAAP to IFRS. Given the similarities between US GAAP and CGAAP, this knowledge should still be applicable.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #4 List 1

Interrogatory

Reference: General

Has HONI undertaken any analysis or is HONI aware of any modelling/analysis undertaken by others regarding the long term rate impacts of IFRS vs GAAP? If yes, please provide the results.

Response

Hydro One has not undertaken any analysis nor is the Company aware of any modelling/analysis undertaken by others regarding the long term rate impacts of IFRS versus US GAAP.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #5 List 1

Interrogatory

Reference: General

Please provide a projection of revenue requirement impacts over the next 5 years for USGAAP vs IFRS, complete with a statement of assumptions.

Response

The following table summarizes the revenue requirement impacts over the next 5 years of using US GAAP in place of IFRS for Hydro One Transmission and Hydro One Distribution. The same annual impact upon OM&A and capital expenditures was assumed for each.

USGAAP vs IFRS	2012	2013	2014	2015	2016
Distribution					
OM&A	(170)	(170)	(170)	(170)	(170)
Depreciation	3	8	13	19	24
Return on rate base	3	11	19	26	36
PILs	(2)	(3)	(2)	(1)	(2)
Annual Revenue Requirement-US GAAP	(166)	(154)	(140)	(126)	(112)
Capital Expenditures	170	170	170	170	170
Rate Base	33	138	237	331	451
Transmission					
OM&A	(200)	(200)	(200)	(200)	(200)
Depreciation	2	5	8	11	14
Return on rate base	3	14	23	32	40
PILs	(1)	(1)	(2)	(2)	(2)
Annual Revenue Requirement-US GAAP	(195)	(183)	(171)	(159)	(147)
Capital Expenditures	200	200	200	200	200
Rate Base	48	175	290	402	511
Assumptions					
Tx Long Term Debt	5.5%	5.6%	5.7%	5.8%	5.9%
Dx Long Term Debt	5.5%	5.6%	5.7%	5.8%	5.9%
Short Term Debt	5.2%	6.2%	6.8%	6.8%	6.8%
ROE	10.4%	10.3%	10.4%	10.5%	10.5%
Tax	26.25%	25.5%	25.0%	25.0%	25.0%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #1 List 1

Interrogatory

Reference: Exhibit C/Tab 1/Schedule 1, page 4

a) The Evidence states that "the adoption of US GAAP will improve Hydro One's ability to benchmark with other large North American utilities and other entities which are retaining or adopting US GAAP". Please outline Hydro One's plans for benchmarking the performance of both its transmission and distribution businesses against that of other large North American utilities.

Response

Hydro One will provide information on performance benchmarking as part of its next cost of service proceeding.

However, any North American utility benchmarking studies, which include costs, that Hydro One may participate in will be more relevant and meaningful if Hydro One utilizes US GAAP, like most study participants, rather than IFRS. For example, Hydro One participates in benchmarking studies conducted by First Quartile Consulting which include a large community of US utilities (for example, see EB-2010-0002 Exhibit I, Tab 4, Schedule 22); the results of these studies would be more relevant if Hydro One utilizes US GAAP in lieu of MIFRS.

Further, special studies such as the Hydro One 2009 Vegetation Management Benchmarking study filed in EB-2009-0096 (see Exhibit A, Tab 15, Schedule 2, Attachment 1 in that proceeding) which consider costs of US utilities will be more relevant if Hydro One adopts US GAAP in lieu of MIFRS.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #2 List 1

Interrogatory

Reference: Exhibit B/Tab 1/Schedule 1
EB-2008-0408, Addendum to Report of the Board (June 2011), pages 19-20

a) It is noted that the OSC approval for Hydro One to use US GAAP terminates January 1, 2015 (at the latest). In its June 2011 Addendum the Board stated that "adoption of USGAAP as a short term solution may be counter-productive". In view of this comment, please explain why it is appropriate for Hydro One to adopt US GAAP for what appears will be a short-term period.

Response

Hydro One cannot determine at this time whether US GAAP will only be required over the short-term. As can be seen from Hydro One's application to the Ontario Securities Commission (Exhibit B, Tab 1, Schedule 2), the use of US GAAP was sought and granted as a solution to the continuing uncertainty on how the regulatory accounting issue will eventually be resolved within IFRS. At this time, it appears highly improbable that the current inconsistency in regulatory accounting guidance issued by the US and International Financial Accounting Standards Boards will be resolved in time to allow for convergence between the two sets of accounting standards by the end of 2014. In fact, the path forward toward the adoption of IFRS by the US remains very unclear, as does the timing of such convergence. Regulatory accounting is not an active project on the International Accounting Standards Board's current work agenda and normal project timelines would make the achievement of a final standard by the end of 2014 a very aggressive target even if this was a high priority project, which it is not.

Hydro One cannot at this time determine what will happen after 2014. The possibilities are numerous and include, but are not limited to, retention of US GAAP through an extended or even permanent OSC exception, retention of US GAAP through the vehicle of Hydro One becoming an SEC registrant as it was previously, or an adoption of IFRS in 2015.

It is important to consider that use of US GAAP for external reporting purposes coincident with the use of MIFRS for rate making purposes will introduce significant additional complexity and costs to Hydro One Networks' Transmission and Distribution businesses, even over a limited three–year period. Approval to use US GAAP for rate making purposes will avoid these additional issues and allow for continued stability in rates while transitioning from CGAAP.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #3 List 1

Interrogatory

Reference: Exhibit D1/Tab 1/Schedule 1, pages 3-4

a) Based on Hydro One's "initial review" of the differences between Canadian and US GAAP, will there be any impacts on the its 2012 expense statement or balance sheet in moving from one to the other? If so, please itemize the impacts and explain the difference in the two accounting treatments that gives rise to each.

Response

Hydro One has only identified the overhead and indirect cost capitalization policy impact to date. Any future impacts would be recorded in the Impact for US GAAP Deferral Account. See also Exhibit I, Tab 1, Schedule 21.