Requirement:

Latest regulated annual reports of NSPI and Emera.

Submission:

Please refer to Attachment 1 for NS Power's 2011 Management's Discussion & Analysis and Attachment 2 for NS Power's 2011 Financial Statements.

Please refer to Attachment 3 for Emera's 2011 Management's Discussion & Analysis and Attachment 4 for Emera's 2011 Financial Statements.

Please refer to Partially Confidential Attachment 5 for NS Power's 2011 Regulated Financial Statements.

Nova Scotia
POWER
An Emera Company

Management's Discussion & Analysis

As at February 8, 2012

Management's Discussion and Analysis ("MD&A") provides a review of the results of operations of Nova Scotia Power Inc. during the fourth quarter of 2011 relative to 2010; and the full year 2011 relative to 2010 and 2009; and its financial position as at December 31, 2011 relative to 2010. To enhance shareholders' understanding, certain multi-year historical financial and statistical information is presented. Throughout this discussion, "NSPI" and "Company" refer to Nova Scotia Power Inc.

Effective January 1, 2011, Nova Scotia Power Inc. changed the basis of presentation of its financial statements, including the application of rate-regulated accounting, from Canadian Generally Accepted Accounting Principles ("CGAAP") to United States Generally Accepted Accounting Principles ("USGAAP"). Information derived from the Statements of Income for the three months and year ended December 31, 2010 and Balance Sheets as at December 31, 2010, along with other select financial information for 2010 and 2009 has been adjusted to reflect USGAAP and is clearly labeled "adjusted".

This discussion and analysis should be read in conjunction with the Nova Scotia Power Inc. annual audited financial statements and supporting notes as at and for the year ended December 31, 2011, prepared in accordance with USGAAP.

Nova Scotia Power Inc.'s accounting policies are subject to examination and approval by the Nova Scotia Utility and Review Board ("UARB"). The rate-regulated accounting policies of Nova Scotia Power Inc. may differ from those used by non-regulated companies with respect to the timing of recognition of certain assets, liabilities, revenues and expenses.

All amounts are in Canadian dollars ("CAD").

Additional information related to NSPI, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com.

Forward Looking Information

This MD&A contains "forward-looking information" within the meaning of applicable Canadian securities laws and "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 (collectively, "forward-looking information"). The words "anticipates", "believes", "could", "estimates", "expects", "intends", "may", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this MD&A includes statements which reflect the current view with respect to the Company's objectives, plans, financial and operating performance, business prospects and opportunities. The forward-looking information reflects management's current beliefs and is based on information currently available to NSPI's management and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the times at which, such events, performance or results will be achieved.

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations are discussed in the Outlook section of the MD&A and may also include: regulatory risk; operating and maintenance risks; economic conditions; availability and price of energy and other commodities; capital resources and liquidity risk; weather; commodity price risk; competitive pressures; construction; derivative financial instruments and hedging availability and cost of financing; interest rate risk; counterparty risk; competitiveness of electricity; commodity supply; environmental risks; foreign exchange; regulatory and government decisions including changes to environmental, financial reporting and tax legislation; loss of service area; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on forward-looking information as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, NSPI undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

Structure of MD&A

This MD&A begins with an Introduction and Strategic Overview, followed by the Financial Review of the Statements of Income, Balance Sheets and Statements of Cash Flows; then continues with a discussion on Outlook, Liquidity and Capital Resources, Pension Funding, Off-Balance Sheet Arrangements, Transactions with Related Parties, Risk Management and Financial Instruments, Disclosure and Internal Controls, Significant Accounting Policies and Critical Accounting Estimates, Changes in Accounting Policies and Practices, Summary of Quarterly Results, Operating Statistics and a Three Year Financial Summary.

INTRODUCTION AND STRATEGIC OVERVIEW

NSPI was created in 1992 through the privatization of the crown corporation Nova Scotia Power Corporation ("NSPC"). NSPI is a fully-integrated regulated electric utility and the primary electricity supplier in Nova Scotia. NSPI has $3.9 billion of assets and provides electricity generation, transmission and distribution services to approximately 493,000 customers. The Company owns 2,374 megawatts ("MW") of generating capacity, of which approximately 52 percent is coal-fired; natural gas and/or oil comprise another 28 percent of capacity; and hydro and wind total 20 percent. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP"). These IPPs own 229 MW, increasing to 259 MW in 2012, of wind and biomass fueled generation capacity. A further 83 MW of renewable capacity is being built directly or purchased under long-term contracts by NSPI and is expected to be in service by the end of 2013. NSPI also owns approximately 5,000 kilometers of transmission facilities and 26,000 kilometers of distribution facilities. The Company has a workforce of approximately 1,900 people.

NSPI is a public utility as defined in the Public Utilities Act (Nova Scotia) ("Act") and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. The Company is not subject to a general annual rate review process, but rather participates in hearings from time to time at the Company's or the UARB's request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's target regulated return on equity ("ROE") range for 2011 is 9.1 percent to 9.6 percent, based on an actual, average regulated common equity component of up to 40 percent of regulated capitalization. The 2012 General Rate Decision adjusted the 2012 ROE range to 9.1 percent to 9.5 percent.

In 2009, the UARB approved a fuel adjustment mechanism ("FAM") allowing NSPI to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

Although the market in Nova Scotia is otherwise mature, the transformation of energy supply to lower emission sources has created the opportunity for organic growth within NSPI as new investments are made in renewable generation and transmission.

Non-GAAP Financial Measure

NSPI uses a financial measure that does not have a standardized meaning under USGAAP.

"Electric margin" is a non-GAAP financial measure used by NSPI and is defined as "Electric revenues" less "Fuel for generation and purchased power" and "Fuel for generation and purchased power – affiliates", net of the "Fuel adjustment", fuel-related foreign exchange losses or gains and other fuel-related costs. This measure is disclosed as management believes it provides useful information regarding the effect of the FAM on NSPI's operations. Electric margin is discussed in the Review of 2011 section.

Developments

UARB Decision on 2012 Fuel Adjustment Mechanism

On December 19, 2011, the UARB approved NSPI's customer rates associated with the 2012 FAM adjustment related to the recovery of prior period fuel costs. The recovery of these costs began January 1, 2012. The approved customer rates seek to recover $69.0 million of prior years' unrecovered fuel costs in 2012.

United States Securities and Exchange Commission Registration Status

Consistent with several Canadian industry peers, NSPI requested and received an exemption from Canadian securities regulators allowing it to continue to report its financial results in accordance with USGAAP. On December 12, 2011, NSPI filed with the United States Securities Exchange Commission ("SEC"), to remove from registration all unsold debt securities as of that date. NSPI also filed to terminate its reporting obligations under Section 15(d) of the United States Securities Exchange Act of 1934, as amended ("the Exchange Act").

2012 General Rate Decision

On May 13, 2011, NSPI filed a General Rate Application ("GRA") with the UARB requesting an average 7.3 percent rate increase across all customer classes effective January 1, 2012. On November 29, 2011, the UARB approved a settlement agreement between NSPI and customer representatives which resulted in an average rate increase of 5.1 percent for all customers, effective January 1, 2012. Rates were approved based on a 9.2 percent ROE, applied to a 37.5 percent common equity component with a target earnings range of 9.1 percent to 9.5 percent on maximum actual equity of 40 percent.

NewPage Port Hawkesbury Corp.

On September 9, 2011, NewPage Port Hawkesbury Corp. ("NewPage"), NSPI's largest customer was granted creditor protection under the Companies' Creditors Arrangement Act ("CCAA"). On September 7, 2011, NewPage Group Inc., NewPage's corporate parent, commenced a voluntary case under Chapter 11 of the United States Bankruptcy Code. NewPage has suspended operations and is actively seeking a buyer for its facility. In light of this, the 2012 General Rate Decision, approved by the UARB, provides for any unrecovered non-fuel electric charges in 2012 related to this customer to be deferred and recovered beginning in 2013. NewPage was also responsible for the engineering, procurement and construction of a 60 MW biomass facility in Port Hawkesbury, Nova Scotia for NSPI. NSPI is proceeding with this project and has assumed full project management responsibilities.

Canadian Environmental Regulations

On August 19, 2011, Environment Canada announced proposed regulations for a new national carbon dioxide framework for the electricity sector in Canada. These proposed regulations would apply to new coal-fired electricity generation units; and existing coal-fired electricity generation units that have reached the end of their deemed economic life of forty-five years after commissioning. These proposed regulations will be effective July 1, 2015. Nova Scotia's existing greenhouse gas regulations require reductions in NSPI's emissions similar to those reflected in the federal framework. NSPI is engaged with federal and provincial agencies in reviewing the implications of this federal framework and its alignment with its current operating plans under existing Nova Scotia regulations.

Deferral of Certain Tax Benefits Decision

In December 2010, the UARB granted NSPI approval to defer $14.5 million of tax benefits which arose in 2010 related to renewable energy projects. On July 21, 2011, the UARB approved an agreement NSPI reached with stakeholders to apply the deferral against the FAM regulatory asset, which reduced the FAM regulatory asset effective January 1, 2011. The application of the deferral reduced the amount of the FAM balance outstanding with the reduction applied to the amount that would otherwise be recovered from customers in 2012 as noted in the "UARB Decision on 2012 Fuel Adjustment Mechanism" section above.

Light–emitting Diode Streetlight Legislation

On May 19, 2011, the Nova Scotia Government passed legislation making light-emitting diode ("LED") lighting mandatory on Nova Scotia's roads and highways. This legislation builds on previous initiatives focused on energy efficiency and environmental responsibility. The cost to convert to LED lighting province-wide is estimated to be in the range of $100 million. NSPI's related capital costs will be subject to UARB review and approval.

Nova Scotia Provincial Environmental Regulations

On May 19, 2011, the Nova Scotia Government approved The Electricity Act (Amended) to facilitate the eligibility of energy from the Lower Churchill Project in Labrador as a resource for meeting Nova Scotia's renewable electricity targets. The amendment requires regulations to be developed that increase the percentage of renewable energy in the generation mix from the planned 25 percent in 2015, to 40 percent by 2020.

On April 11, 2011, the Nova Scotia Government announced that the cap on the annual amount of new forest biomass that can be used to generate electricity will be lowered by 30 percent to 350,000 dry tonnes per year. NSPI's 60 MW Port Hawkesbury Biomass Project is unaffected by this announcement.

Depreciation Settlement

On May 11, 2011, the UARB approved changes to NSPI's depreciation rates following NSPI's completion of a depreciation study and a settlement agreement with stakeholders. The overall impact on the average depreciation rate is immaterial. The new depreciation rates are effective January 1, 2012, as approved by the UARB in the 2012 General Rate Decision.

Digby Wind Renewable Energy Project

On March 9, 2011, the UARB approved a capital work order for the Digby Wind Renewable Energy Project, which included a substation, network upgrades and interconnection costs, in the total amount of $79.8 million. This project went into service in December 2010.

Appointments

Directors

Ray Ivany, President and Vice-Chancellor of Acadia University, joined NSPI's Board of Directors on September 22, 2011.

James Eisenhauer, FCA was appointed Chairman of NSPI's Board of Directors on May 2, 2011, replacing George A Caines, QC, who retired. On May 4, 2011, Mr. Eisenhauer was elected to Emera Incorporated's ("Emera") Board of Directors at Emera's Annual General Meeting.

Executive

Judy Steele, FCA was appointed Chief Financial Officer ("CFO") of NSPI on May 16, 2011, on an interim basis until such time as a permanent CFO is named.

REVIEW OF 2011
Statements of Income

For the millions of Canadian dollars	Three months ended December 31				Year ended December 31
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Operating revenues	**$289.2**	$303.2	**$1,233.0**	$1,191.4	$1,211.8
Fuel for generation and purchased power	**127.0**	146.1	**546.3**	578.6	525.8
Fuel for generation and purchased power – affiliates (1)	**0.8**	0.1	**1.1**	8.1	(25.1)
Fuel adjustment	**(4.5)**	(24.0)	**(8.5)**	(99.0)	8.5
Operating, maintenance and general	**75.0**	67.5	**268.6**	245.8	223.9
Provincial grants and taxes	**9.8**	10.1	**38.7**	40.1	40.5
Depreciation and amortization	**58.8**	63.7	**187.2**	188.1	171.5
Total operating expenses	**266.9**	263.5	**1,033.4**	961.7	945.1
Income from operations	**22.3**	39.7	**199.6**	229.7	266.7
Other expenses, net	**2.1**	3.5	**8.9**	11.3	3.3
Interest expense, net	**23.6**	26.8	**104.2**	104.7	102.8
Income before provision for income taxes	**(3.4)**	9.4	**86.5**	113.7	160.6
Income tax (recovery) expense	**(27.5)**	(12.4)	**(44.9)**	(13.4)	40.3
Net income of Nova Scotia Power Inc.	**24.1**	21.8	**131.4**	127.1	120.3
Preferred stock dividends	**1.9**	1.9	**7.9**	7.9	9.5
Net income attributable to common shareholders	**$22.2**	$19.9	**$123.5**	$119.2	$110.8

(1) Fuel for generation and purchased power – affiliates includes proceeds from the sale of natural gas.

NSPI's net income attributable to common shareholders increased $2.3 million to $22.2 million in Q4 2011 compared to $19.9 million in Q4 2010 (adjusted). For the year ended December 31, 2011, NSPI's net income attributable to common shareholders increased $4.3 million to $123.5 million in 2011 compared to $119.2 million in 2010 (adjusted) and $110.8 million in 2009 (adjusted).

Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Net income attributable to common shareholders – 2009 (adjusted)		**$110.8**
Decreased electric margin (see Electric Margin section for explanation)		(11.6)
Increased operating, maintenance and general ("OM&G") expenses primarily due to increased pension, storm costs and customer service initiatives		(21.9)
Increased net depreciation and amortization primarily due to increased property, plant and equipment and increased regulatory amortization		(16.1)
Decreased other expenses, net primarily due to increased allowance for equity funds used during construction related to increased capital spending		4.3
Decreased income taxes primarily due to decreased income before provision for income taxes, deductions related to renewable investments and a change in the expected benefit from other accelerated tax deductions		53.7
Net income attributable to common shareholders – 2010 (adjusted)	**$19.9**	**$119.2**
Decreased electric margin (see Electric Margin section for explanation)	(12.6)	(6.9)
Increased OM&G expenses primarily due to increased pension costs, plant maintenance costs and labour escalation	(7.5)	(22.8)
Decreased net depreciation and amortization primarily due to decreased regulatory amortization partially offset by increased property, plant and equipment	4.7	1.7
Increased income tax recovery primarily due to a change in the expected benefit from accelerated tax deductions and decreased income before provision for income taxes	15.1	31.5
Other	2.6	0.8
Net income attributable to common shareholders – 2011	**$22.2**	**$123.5**

Balance Sheets Highlights

millions of Canadian dollars	**2011**	2010 (adjusted)	As at December 31 2009 (adjusted)
Total assets	**$3,897.0**	$3,804.7	$3,493.8
Total long-term liabilities	**2,542.7**	2,481.0	1,855.8

Significant changes in the balance sheets between December 31, 2011 and 2010 (adjusted) include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Receivables, net	**16.1**	Increased due to higher fuel-related electricity pricing effective January 1, 2011 and timing of billings and receipts.
Derivative instruments (current and long-term)	**(15.4)**	Decreased primarily due to settlements and unfavourable commodity price positions, partially offset by favourable United States dollars ("USD") price positions.
Property, plant and equipment, net of accumulated depreciation	**108.1**	Increased primarily due to capital spending, partially offset by depreciation.
Deferred income taxes (long-term)	**(16.8)**	Decreased primarily due to increased deferred income tax liability on property, plant and equipment, including renewable investments, resulting in reclassification to deferred income tax liability.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**27.4**	Increased debt levels.
Accounts payable	**(13.7)**	Decreased primarily due to release of holdbacks and timing of vendor payments.
Deferred income taxes (current and long-term)	**28.7**	Increased primarily due to increased deferred income tax liability on property, plant and equipment, including renewable investments, resulting in reclassification of a deferred income tax asset.
Derivative instruments (current and long-term)	**12.1**	Increased primarily due to unfavourable commodity price positions, partially offset by favourable USD price positions.
Regulatory liabilities (current and long-term)	**(61.6)**	Decreased deferred income tax regulatory liability, decreased derivative regulatory liability and decreased regulatory liability related to the 2010 renewable tax benefits deferral.
Pension and post-retirement liabilities (current and long-term)	**105.4**	Increased primarily due to a change in the discount rate used in determining the pension and post-retirement obligations, and 2011 investment losses.
Asset retirement obligations ("ARO")	**(47.6)**	Decreased primarily due to change in estimates of retirement dates and future decommissioning costs.
Common stock	**50.0**	Issuance of common shares.
Accumulated other comprehensive loss ("AOCL")	**111.0**	Net change due to underfunded amount in pension plan resulting from a change in the discount rate, and 2011 investment losses.
Retained earnings	**98.5**	Net income in excess of dividends paid.

Cash Flow Highlights

Significant changes in the statements of cash flows between December 31, 2011 and 2010 (adjusted) include:

Year ended December 31 millions of Canadian dollars	**2011**	2010 (adjusted)	Explanation
Cash, beginning of period	**$0.3**	$0.3	
Provided by (used in):			
Operating activities	**272.3**	317.3	Cash provided by operating activities decreased in 2011 primarily due to unfavourable non-cash working capital largely related to changes in receivables due to the settlement of a receivable from a natural gas supplier in 2010 partially offset by increased cash due to the FAM.
Investing activities	**(316.3)**	(542.5)	Cash used in investing activities decreased in 2011 primarily due to lower capital spending largely related to renewable investments.
Financing activities	**43.7**	225.2	Cash provided by financing activities decreased in 2011 primarily due to a lower net increase in debt partially offset by lower common stock dividends in 2011. The lower net increase in debt was due to the issuance of $300 million in long-term debt in 2010 which was partially offset by the retirement of long-term debt of $100 million in 2010 and a lower increase in short-term debt in 2011.
Cash, end of period	**-**	$0.3	

Operating Revenues

NSPI's Operating Revenues include sales of electricity and other services as summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Electric revenues	**$282.9**	$296.4	**$1,209.7**	$1,167.3	$1,188.1
Other revenues	**6.3**	6.8	**23.3**	24.1	23.7
Operating revenues	**$289.2**	$303.2	**$1,233.0**	$1,191.4	$1,211.8

Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal, with Q1 and Q4 the strongest periods, reflecting colder weather and fewer daylight hours in the winter season.

NSPI's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, and the province's universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other revenues consist of export sales, sales to municipal electric utilities and revenues from street lighting.

Electric sales volumes are summarized in the following tables by customer class:

Q4 Electric Sales Volumes
Gigawatt hours ("GWh")

	2011	2010	2009
Residential	**1,073**	1,080	1,091
Commercial	**768**	765	772
Industrial	**568**	957	998
Other	**83**	84	81
Total	**2,492**	2,886	2,942

Annual Electric Sales Volumes
GWh

	2011	2010	2009
Residential	**4,275**	4,147	4,228
Commercial	**3,102**	3,088	3,107
Industrial	**3,516**	3,908	3,642
Other	**313**	312	328
Total	**11,206**	11,455	11,305

Electric revenues are summarized in the following tables by customer class:

Q4 Electric Revenues
millions of Canadian dollars

	2011	2010	2009
Residential	**$141.0**	$137.1	$140.4
Commercial	**85.8**	82.2	84.2
Industrial	**45.2**	66.0	67.3
Other	**10.9**	11.1	11.0
Total	**$282.9**	$296.4	$302.9

Annual Electric Revenues
millions of Canadian dollars

	2011	2010	2009
Residential	**$564.9**	$531.0	$547.3
Commercial	**341.8**	325.4	333.9
Industrial	**260.1**	269.3	263.8
Other	**42.9**	41.6	43.1
Total	**$1,209.7**	$1,167.3	$1,188.1

Electric revenues decreased $13.5 million to $282.9 million in Q4 2011 compared to $296.4 million in Q4 2010. For the year ended December 31, 2011, electric revenues increased $42.4 million to $1,209.7 million compared to $1,167.3 million in 2010 and $1,188.1 million in 2009. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Electric revenues – 2009		**$1,188.1**
Decreased fuel-related electricity pricing effective January 1, 2010		(22.4)
Change in residential and commercial sales volumes primarily due to warmer weather		(10.7)
Increased industrial sales volumes from several large industrial customers		13.2
Other		(0.9)
Electric revenues – 2010	**$296.4**	**$1,167.3**
Increased fuel-related electricity pricing effective January 1, 2011	11.5	51.5
Year-over-year increased residential sales volumes due to load growth and colder weather	(1.2)	15.2
Decreased industrial sales volume primarily due to suspended operations of a large industrial customer	(23.2)	(24.1)
Other	(0.6)	(0.2)
Electric revenues – 2011	**$282.9**	**$1,209.7**

Electric Margin

NSPI distinguishes revenues related to the recovery of fuel costs ("fuel electric revenues") from revenues related to the recovery of non-fuel costs ("non-fuel electric revenues") because the FAM introduced on January 1, 2009 enables NSPI to seek recovery of fuel costs through regularly scheduled rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year. Consequently, fuel electric revenues and fuel costs do not have a material effect on NSPI's electric margin or net income, with the exception of the incentive component of the FAM, whereby NSPI retains or absorbs 10 percent of the over or under recovered amount to a maximum of $5 million.

As fuel costs are recovered through the FAM, electric margin and net income are influenced primarily by revenues relating to non-fuel costs. NSPI's customer classes contribute differently to the Company's non-fuel electric revenues with residential and commercial customers contributing more than industrials. Accordingly, changes in residential and commercial load, largely due to weather and growth, have the largest effect on non-fuel electric revenues. Changes in industrial load, which are generally due to economic conditions, have less of an effect on non-fuel electric revenues than a similar volume change in residential and commercial load.

Electric margin is summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31				Year ended December 31
	2011	2010	**2011**	2010	2009
Fuel electric revenues – current year	**$115.6**	$129.1	**$512.6**	$513.7	$509.3
Fuel electric revenues – preceding years	**6.1**	(5.7)	**26.6**	(22.4)	-
Non-fuel electric revenues	**161.2**	173.0	**670.5**	676.0	678.8
Total electric revenues	**$282.9**	$296.4	**$1,209.7**	$1,167.3	$1,188.1
Fuel for generation and purchased power, including affiliates	**(127.8)**	(146.2)	**(547.4)**	(586.7)	(500.7)
Fuel adjustment	**4.5**	24.0	**8.5**	99.0	(8.5)
Foreign exchange and other fuel-related costs	**(1.4)**	(3.4)	**(7.4)**	(9.3)	3.0
Electric margin	**$158.2**	$170.8	**$663.4**	$670.3	$681.9

NSPI's electric margin decreased $12.6 million to $158.2 million in Q4 2011 compared to $170.8 million in Q4 2010 primarily due to decreased large industrial sales. For the year ended December 31, 2011, NSPI's electric margin decreased $6.9 million to $663.4 million compared to $670.3 million in 2010 primarily due to decreased large industrial sales, partially offset by increased residential sales as a result of load growth and colder weather. NSPI's electric margin decreased in 2010 to $670.3 million from $681.9 million in 2009 due to lower residential sales related to warmer weather and the recognition of a FAM incentive expense compared to a recovery in 2009.

Q4 Average Electric Margin / Megawatt hour ("MWh")			
	2011	2010	2009
Dollars per MWh	**$63**	$59	$59

Annual Average Electric Margin / MWh			
	2011	2010	2009
Dollars per MWh	**$59**	$59	$60

The change in average electric margin per MWh in Q4 2011 compared to Q4 2010 reflects a change in sales volume mix largely due to decreased large industrial sales.

The change in average electric margin per MWh in 2010 compared to 2009 reflects a change in sales volume mix and recognition of a FAM incentive expense in 2010 compared to a recovery in 2009.

Fuel for Generation and Purchased Power (including affiliates)

Capacity

To ensure reliability of service, NSPI maintains a generating capacity greater than firm peak demand. The total Company-owned generation capacity is 2,374 MW, which is supplemented by 229 MW contracted with IPPs. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area and the Northeast Power Coordinating Council.

NSPI facilities continue to rank among the best in Canada on capacity related performance indicators. The high availability and capability of low cost thermal generating stations provide lower cost energy to customers. In 2011, thermal plant availability was unchanged from 2010 at 87 percent. Sustained high availability and low forced outage rates on low cost facilities are good indicators of sound maintenance and investment practices.

Q4 Production Volumes
GWh

	2011	2010	2009
Coal and petcoke	**1,624**	2,049	2,069
Natural gas	**482**	438	534
Oil	**7**	16	16
Renewables	**327**	340	281
Purchased power	**298**	315	335
Total	**2,738**	3,158	3,235

Purchased power includes 227 GWh of renewables in Q4 2011 (2010 – 175 GWh; 2009 – 92 GWh).

Annual Production Volumes
GWh

	2011	2010	2009
Coal and petcoke	**6,848**	7,839	8,177
Natural gas	**2,430**	2,275	1,612
Oil	**35**	36	307
Renewables	**1,335**	1,017	1,065
Purchased power	**1,269**	997	931
Total	**11,917**	12,164	12,092

Purchased power includes 743 GWh of renewables in 2011 (2010 – 526 GWh; 2009 – 301 GWh).

Q4 Average Unit Fuel Costs

	2011	2010	2009
Dollars per MWh	**$47**	$46	$43

Annual Average Unit Fuel Costs

	2011	2010	2009
Dollars per MWh	**$46**	$48	$41

NSPI's percentage of solid fuel generation decreased to approximately 57 percent in 2011, down from 64 percent in 2010 and 68 percent in 2009. Economic dispatch of the generating fleet brings the lowest cost options on stream first, such that the incremental cost of production increases as sales volume increases. Historically, solid fuels have had the lowest per unit fuel cost, after hydro and NSPI-owned wind, which have no fuel cost component. Natural gas, oil, and purchased power have the next lowest fuel cost, depending on the relative pricing of each. During 2011, natural gas represented a higher percentage of the annual energy requirement than prior years as economic dispatch favored natural gas for much of the year. Additionally, the introduction of new renewable generation has decreased coal consumption.

The average unit fuel costs decreased in 2011 compared to 2010 primarily due to decreased natural gas prices and increased hydro and wind production.

The average unit fuel costs increased in 2010 compared to 2009 primarily due to higher priced imported coal and solid fuel commodity mix related to emission compliance.

A large portion of NSPI's fuel supply comes from international suppliers, and is subject to commodity price and foreign exchange risk. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts and utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. Foreign exchange risk is managed through forward and swap contracts. Fuel contracts may also be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. Further details on the Company's risk management strategies related to fuel for generation and purchased power are discussed in the Business Risks section.

Fuel for generation and purchased power, including affiliates decreased $18.4 million to $127.8 million in Q4 2011 compared to $146.2 million in Q4 2010. For the year ended December 31, 2011, fuel for generation and purchased power, including affiliates decreased $39.3 million to $547.4 million compared to $586.7 million in 2010 and $500.7 million in 2009.

Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Fuel for generation and purchased power, including affiliates – 2009		**$500.7**
Commodity price and volume increases		34.5
Changes in generation mix and plant performance		24.3
Solid fuel commodity mix and additives related to emission compliance		25.3
Valuation of contract receivable (see discussion below)		8.7
Increased sales volume		2.7
Increased hydro production		(1.1)
Increased proceeds from the resale of natural gas		(9.8)
Mark-to-market on natural gas hedges recognized in 2009 as they were no longer required due to decreased 2009 production volumes		2.2
Other		(0.8)
Fuel for generation and purchased power, including affiliates – 2010	**$146.2**	**$586.7**
Valuation of contract receivable (see discussion below)	3.2	27.8
Changes in generation mix and plant performance	(3.9)	12.0
Decreased commodity prices	(1.0)	(38.9)
Decreased (increased) hydro and wind production	0.6	(19.9)
Changes in solid fuel commodity mix and additives related to emission compliance	3.2	(7.3)
Decreased sales volume	(18.8)	(8.3)
Other	(1.7)	(4.7)
Fuel for generation and purchased power, including affiliates – 2011	**$127.8**	**$547.4**

NSPI had a long-term contract receivable with a natural gas supplier that was required to be fair-valued. The natural gas supply contract settled in November 2010. The fair value related to the contract had a favourable impact on natural gas pricing during 2010. The effect is segregated in the table above.

Fuel Adjustment

The regulated fuel adjustment related to the fuel adjustment mechanism ("FAM") for NSPI includes the effect of fuel costs in both the current and two preceding years specifically:

- The difference between actual fuel costs and amounts recovered from customers in the current year. This amount, net of the incentive component, is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities".
- The recovery from (rebate to) customers of under (over) recovered fuel costs from prior years.

On December 19, 2011, the UARB approved NSPI's customer rates associated with the 2012 FAM adjustment related to the recovery of prior period fuel costs. The recovery of these costs began January 1, 2012. The approved customer rates seek to recover $69.0 million of prior years' unrecovered fuel costs in 2012.

In December 2010, as part of the FAM regulatory process, the UARB approved NSPI's setting of the 2011 base cost of fuel and the under-recovered fuel-related costs from prior years. The UARB approved the recovery of the prior year FAM balance from customers over three years, effective January 1, 2011, with 50 percent to be recovered in 2011, 30 percent in 2012 and 20 percent in 2013.

Details of the FAM regulatory asset are summarized in the following table:

millions of Canadian dollars	**2011**	2010	2009
FAM regulatory asset (liability) – Balance at January 1	**$92.9**	$(9.9)	-
Under (over) recovery of current year fuel costs	**35.1**	76.6	$(8.5)
(Recovery from) rebate to customers of prior years' fuel costs	**(26.6)**	22.4	-
Application of deferral related to tax benefits from 2010	**(14.5)**	-	-
Interest revenue (expense) on FAM balance	**6.8**	3.8	(1.4)
FAM regulatory asset (liability) – Balance at December 31	**$93.7**	$92.9	$(9.9)

NSPI has recognized a deferred income tax expense related to the fuel adjustment based on NSPI's enacted statutory income tax rate. As at December 31, 2011, NSPI's deferred income tax liability related to the FAM was $29.0 million (2010 – $29.2 million).

Provincial Grants and Taxes

NSPI pays annual grants to the Province of Nova Scotia in lieu of municipal taxation other than deed transfer tax.

Regulatory Amortization

Regulatory amortization is included in depreciation and amortization. Regulatory amortization decreased $7.7 million to $16.0 in Q4 2011 compared to $23.7 million in Q4 2010 and decreased $17.8 million to $19.1 million for the year ended December 31, 2011 compared to $36.9 million in 2010 primarily due to a $14.5 million deferral of certain tax benefits arising in 2010 related to renewable energy projects and decreased discretionary regulatory amortization recorded in 2011, as discussed below.

Regulatory amortization increased $9.7 million to $36.9 million for the year ended December 31, 2010 compared to $27.2 million in 2009 primarily due to a $14.5 million deferral of certain tax benefits arising in 2010 related to renewable energy projects as approved by the UARB, partially offset by a reduction in amortization of the pre-2003 income tax regulatory asset resulting from the UARB's 2010 ROE decision of $4.8 million in 2010 (2009 – $10.0 million). The 2010 ROE decision allows NSPI to recognize additional amortization amounts in current periods and to reduce amortization in future periods to provide flexibility relating to customer rate requirements.

Other Expenses, Net

Other expenses, net decreased $1.4 million to $2.1 million in Q4 2011 compared to $3.5 million in Q4 2010 (adjusted) and decreased $2.4 million to $8.9 million for the year ended December 31, 2011 compared to $11.3 million in 2010 (adjusted) primarily due to decreased foreign exchange losses recovered through the FAM.

Other expenses, net increased $8.0 million to $11.3 million for the year ended December 31, 2010 (adjusted) compared to $3.3 million in 2009 (adjusted) primarily due to increased foreign exchange losses, recovered through the FAM, partially offset by increased allowance for equity funds used during construction related to increased capital spending.

Income Taxes

In 2011, NSPI was subject to provincial capital tax (0.075 percent), corporate income tax (32.5 percent) and Part VI.1 tax relating to preferred stock dividends (40 percent). NSPI also receives a reduction in its corporate income tax otherwise payable related to the Part VI.1 tax deduction (29 percent of preferred stock dividends).

In Q4 2011, NSPI modified its estimate of the expected tax benefit of tax deductions, electing to amend its tax returns for the years 2006 through 2009. This resulted in a $23.3 million reduction in income tax expense and a $3.0 million increase in interest revenue, recorded in the quarter. This change in accounting estimate has been accounted for on a prospective basis.

In Q4 2010, NSPI revised its estimate of the 2010 expected benefit from accelerated tax deductions, resulting in a $7.2 million reduction in income tax expense.

OUTLOOK

Economic Environment

NSPI will continue to pursue investments related to the transformation of the energy industry to lower emissions and comply with renewable energy standards. This will also include improvements to the transmission system.

Environmental Legislation

NSPI is subject to environmental regulations as set by both the Province of Nova Scotia and the Government of Canada. The Company continues to work with officials at both levels of government so as to comply with these regulations in an integrated way.

Operations

NSPI anticipates earning a regulated ROE within its allowed range in 2012. NSPI continues to implement its strategy, which is focused on regulated investments in renewable energy and system reliability projects with an annual capital expenditure plan of approximately $330 million in 2012 as detailed below. The company expects to finance its capital expenditures with funds from operations and debt.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates cash primarily through the generation, transmission and distribution of electricity. NSPI's customer base is diversified by both sales volumes and revenues among customer classes. Circumstances that could affect the Company's ability to generate cash include general economic downturns in NSPI's markets, the loss of one or more large customers, regulatory decisions affecting customer rates and changes in environmental legislation.

In addition to internally generated funds, NSPI has access to a $500 million committed syndicated revolving bank line of credit, as discussed in the table below. In August 2011, NSPI reduced its committed syndicated revolving bank line from $600 million to $500 million, and the maturity was extended from June 2013 until June 2015. NSPI has an active commercial paper program for up to $400 million, of which outstanding amounts are 100 percent backed by the Company's bank line referred to above, which results in an equal amount of credit being considered drawn and unavailable.

As at December 31, 2011, the Company's total credit facility, outstanding borrowings and available capacity were as follows:

millions of Canadian dollars	Maturity	Revolving Credit Facility	Utilized	Undrawn and available
Operating credit facility	June 2015 – Revolver	$500	$318	$182

NSPI has debt covenants associated with its credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements.

Debt Management

In May 2011, NSPI filed an amendment to its amended and restated short form base shelf prospectus and an amendment to its prospectus supplement for medium-term notes (unsecured). These amendments increased the aggregate principal amount of debt securities and medium-term notes that may be offered from time to time under the short form base shelf prospectus and prospectus supplements from $500 million to $800 million. As at December 31, 2011, $300 million in medium-term notes have been issued under NSPI's short form base shelf prospectus and prospectus supplement since their initial filing in 2010.

Concurrently with the Canadian filing of these amendments, NSPI also filed a registration statement with the SEC to register debt securities having an aggregate initial offering price of up to $500 million for sale in the United States. As discussed in the Developments section, on December 12, 2011, NSPI filed a post-effective amendment to its registration statement with the SEC, removing from registration all unsold debt securities as of that date.

The weighted average coupon rate on NSPI's outstanding medium-term and debenture notes at December 31, 2011 and 2010 was 6.74 percent. Approximately 27 percent of the debt matures over the next ten years, 70 percent matures between 2022 and 2040, and 3 percent matures in 2097. The quoted yield for the same or similar issues of the same remaining maturities was 3.51 percent as at December 31, 2011 (2010 – 4.50 percent).

NSPI's credit ratings issued by Dominion Bond Rating Service ("DBRS") and Standard & Poor's ("S&P") are as follows:

	DBRS	S&P
Corporate	N/A	BBB+
Senior unsecured debt	A (low)	BBB+
Preferred stock	Pfd-2 (low)	P-2 (low)
Commercial paper	R-1 (low)	A-1 (low)

Contractual Obligations

As at December 31, 2011, commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt (1)	$1,958.5	-	$300.0	-	$323.5	-	$1,335.0
Pension obligations (2)	701.5	$58.6	58.3	$57.7	50.9	$42.2	433.8
Asset retirement obligations	333.5	2.1	2.1	2.1	1.7	2.8	322.7
Purchased power (3)	1,533.9	68.4	81.3	85.2	85.2	85.2	1,128.6
Coal, biomass, oil and natural gas supply	1,032.0	203.5	120.3	64.0	21.9	22.4	599.9
Transportation (4)	71.6	48.8	11.2	10.4	1.2	-	-
Long-term service agreements (5)	28.7	9.7	9.8	4.3	4.4	0.5	-
Capital projects	31.6	30.3	1.3	-	-	-	-
Leases (6)	10.3	1.0	0.9	0.8	0.8	0.5	6.3
Other	0.4	0.4	-	-	-	-	-
Total	$5,702.0	$422.8	$585.2	$224.5	$489.6	$153.6	$3,826.3

(1) NSPI's commercial paper is backed by a revolving credit facility which matures in 2015.
(2) Pension obligations: Defined benefit pension funding contractual obligations are based on regulatory requirements and assume that members stop accruing service effective December 31, 2011. As the defined benefit pension plan currently undergoes annual review to revise contribution requirements and members are still accruing service under the plan, actual future pension contributions will differ from the amounts shown.
(3) Purchased power: annual requirement to purchase 100 percent of electricity production from independent power producers over varying contract lengths up to 25 years.
(4) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on the Maritimes & Northeast Pipeline ("M&NP").
(5) Long-term service agreements: outsourced management of the Company's computer and communication infrastructure and vegetation management.
(6) Leases: operating lease agreements for office space, land leases and rail cars.

Capital Expenditures

Capital expenditures for 2011, including allowance for funds used during construction ("AFUDC"), were approximately $320 million. Significant capital expenditures included the Port Hawkesbury Biomass Project, construction of a 138 kilovolt ("kV") transmission line, the construction completion of the Lower Water Street corporate offices and the replacement of the gas insulated substation at Lower Water Street.

Forecasted Gross Capital Expenditures

For the year ended December 31, 2012 millions of Canadian dollars	Total
Generation	$142
Transmission	68
Distribution	72
General plant and other	48
Total	$330

Significant Individual Capital Projects

Nature of project millions of Canadian dollars	**Pre-2012 Spending**	**2012 Forecast**	**Post-2012 Forecast**	**Expected year of completion**
Port Hawkesbury Biomass	$143	$56	$8	2013
Harbour East Transmission Line	-	1	11	2013
LED Streetlight Conversion	-	6	94	2016
Marshall Falls Hydro Upgrade	-	3	15	2017

PENSION FUNDING

For funding purposes, NSPI determines required contributions to its defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three year period. The cash required in 2012 for defined benefit pension plans will be approximately $66.2 million (2011 – $41.3 million actual). All pension plan contributions are tax deductible and will be funded with cash from operations.

NSPI's defined benefit pension plan employs a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return given the Company's goal of preserving capital within an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation pension assets are overseen by external investment managers per the pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of Canadian and global equities, domestic bonds, and short-term investments. NSPI reviews investment manager performance on a regular basis and adjusts the plans' asset mixes as needed in accordance with the pension plan's investment policy.

NSPI's projected contribution to defined contribution pension plans is $1.6 million for 2012 (2011 – $1.6 million actual).

OFF-BALANCE SHEET ARRANGEMENTS

Upon privatization of the former provincially owned NSPC in 1992, NSPI became responsible for managing a portfolio of defeasance securities, which at December 31, 2011 totaled $1.0 billion. The securities are held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), an affiliate of the Province of Nova Scotia. NSPI is responsible for ensuring the defeasance securities provide the principal and interest streams to match the related defeased NSPC debt. Approximately 73 percent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio; the remaining defeasance portfolio has a market value higher than the related debt, reducing the future risk of this portion of the portfolio.

NSPI had the following guarantees and letters of credits as at December 31, 2011:

- NSPI has provided a limited guarantee for the indebtedness of Renewable Energy Services Ltd. ("RESL"). The guarantee is up to a maximum of $23.5 million. As at December 31, 2011, RESL's indebtedness under the loan agreement was $21.9 million. NSPI holds a security interest in the present and future assets of RESL.

- A financial institution has issued a standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2012 and is renewed annually. The amount committed as at December 31, 2011 was $22.5 million.

No liability has been recognized on the balance sheet related to any potential obligation under these guarantees and letters of credits.

TRANSACTIONS WITH RELATED PARTIES

The Company enters into transactions with related parties in the normal course of operations. All related party transactions with NSPI are governed by an affiliate Code of Conduct that is approved by the UARB.

NSPI, Emera Energy Services ("EES"), Bangor Hydro Electric Company ("Bangor Hydro"), Emera Utility Services ("EUS") and Emera Newfoundland and Labrador ("ENL") are wholly owned subsidiaries of Emera. Emera owns a 12.9 percent interest in the M&NP.

Related party transactions with NSPI are summarized in the following table:

For the millions of Canadian dollars			Three months ended December 31		Year ended December 31	
	Nature of Service	**Presentation**	**2011**	2010	**2011**	2010
Sales:						
Emera	Corporate support and other services	OM&G	**$1.3**	$0.8	**$3.3**	$3.0
Emera	Contract revenues	Operating revenues	**-**	1.0	**-**	1.0
EES	Corporate support and other services	OM&G	**0.3**	0.3	**1.2**	1.2
Bangor Hydro	Corporate support and other services	OM&G	**0.2**	0.2	**0.9**	0.9
Other	Corporate support and other services	OM&G	**0.7**	0.5	**2.0**	1.2
Purchases:						
EES	Net purchase of electricity	Fuel for generation and purchased power – affiliates	**-**	(0.1)	**-**	6.2
EES	Net purchase of natural gas	Fuel for generation and purchased power – affiliates	**0.8**	(0.8)	**1.1**	0.9
Emera	Purchase of power	Fuel for generation and purchased power – affiliates	**-**	1.0	**-**	1.0
EUS	Maintenance services	OM&G	**0.4**	1.5	**5.6**	2.2
EUS	Purchase of inventory	Inventory	**-**	0.2	**0.5**	1.1
EUS	Construction services	Property, plant and equipment	**6.4**	9.8	**16.6**	43.5

Effective Q2 2011, NSPI recorded the impact of two agreements with Emera on a net basis in the statements of income. Under the agreements, NSPI purchased power from Emera and received contract revenues from Emera of $2.9 million (2010 – $1.0 million) for the three months ended December 31, 2011 and $9.8 million (2010 – $1.0 million) for the year ended December 31, 2011.

In the ordinary course of business, the Company purchased $2.7 million (2010 – $4.0 million) in natural gas transportation capacity from M&NP for the three months ended December 31, 2011, and $14.3 million (2010 - $18.0 million) during the year ended December 31, 2011. The amount is recognized in "Fuel for generation and purchased power" and is measured at the exchange amount. As at December 31, 2011, the amount payable to M&NP is $0.8 million (2010 – $1.0 million) and is under normal interest and credit terms.

During the three months ended December 31, 2011 and 2010, no common shares were issued to Emera or an affiliate under common control of Emera. For the years ended December 31, 2011 and 2010, the Company issued 5.0 million common shares to Emera and an affiliate under common control of Emera for total consideration of $50.0 million.

On May 28, 2010, NSPI purchased $30.1 million in wind generation assets under development related to the Digby Wind Project from a subsidiary of Emera. This transaction was measured at the carrying amount of the assets transferred. As at December 31, 2011 and 2010, there were no amounts due.

As at December 31, amounts due (to) from related parties are summarized in the following table:

millions of Canadian dollars	**2011**	2010
Due from related companies:		
Emera	**$0.4**	-
ENL	**0.1**	-
EES	**-**	$0.7
	0.5	0.7
Due to related companies:		
EUS	**(1.7)**	(5.5)
EES	**(0.1)**	-
Emera	**-**	(1.4)
	(1.8)	(6.9)
Net due to related companies	**$(1.3)**	$(6.2)

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

NSPI's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management practices are overseen by the Board of Directors. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operations.

The Company manages its exposure to normal operating and market risks relating to commodity prices and foreign exchange using financial instruments consisting mainly of foreign exchange forwards and swaps, and coal, oil and gas options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. Collectively these contracts are considered "derivatives".

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exception. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty credit worthy. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts where the criteria are no longer met.

Derivatives entered into by NSPI that are documented as economic hedges, and for which the NPNS exception has not been taken, receive regulatory deferral as approved by the UARB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized when the derivatives settle. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates through the FAM.

Regulatory Items Recognized on the Balance Sheets

The Company has the following categories on the balance sheets related to derivatives receiving regulatory deferral:

As at millions of Canadian dollars	**December 31 2011**	December 31 2010 (adjusted)
Derivative instrument assets (including current and other assets)	**$44.5**	$59.9
Regulatory assets (including current and other assets)	**46.3**	34.2
Derivative instrument liabilities (including current and long-term liabilities)	**(46.3)**	(34.2)
Regulatory liabilities (including current and long-term liabilities)	**(44.5)**	(59.9)
Net asset (liability)	**-**	-

Regulatory Impact Recognized in Net Income

The Company recognized the following (losses) gains related to derivatives receiving regulatory deferral as follows:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2011	2010 (adjusted)	**2011**	2010 (adjusted)
Other expenses, net	**-**	$1.0	**-**	$1.5
Fuel for generation and purchased power	**$(3.8)**	(10.9)	**$(21.3)**	(66.8)
Net losses	**$(3.8)**	$(9.9)	**$(21.3)**	$(65.3)

As discussed in note 16 of NSPI's financial statements at the reporting date, various valuation techniques are used to determine the fair value of derivative instruments. These may include quoted market prices or, internal models using observable or non-observable market information.

Business Risks

Measurement of Risk

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. NSPI has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach.

The Company's risk management activities are focused on those areas that most significantly impact NSPI's business, revenues, operating income, net income, net assets or liquidity or capital resources. These risks include, but are not limited to regulatory risk, exposure to commodity prices, foreign exchange, commercial relationships, relationships with employees, credit, weather and interest rate risk and changes in environmental legislation. The nature of risk is such that no list can be comprehensive, and other risks may arise or risks not currently considered material may become material in the future.

Regulatory Risk

NSPI faces risk with respect to the recovery of costs and investments in a timely manner. As a regulated, cost-of-service utility with an obligation to serve, NSPI must obtain regulatory approval to change general electricity rates and riders. Costs and investments can be recovered after and once the UARB has approved recovery in adjustments to rates or riders, which normally requires a public hearing process.

During public hearing processes, consultants and customer representatives scrutinize the Company's costs, actions and plans, and the UARB determines whether to allow recovery and to adjust rates based upon NSPI's evidence and any contrary evidence from other hearing participants. The Company manages this regulatory risk through transparent regulatory disclosure, ongoing stakeholder consultation and multi-party engagement on aspects such as utility operations, rate filings and capital plans. The

Company employs a collaborative regulatory approach through technical conferences and negotiated settlements.

Commodity Price Risk

A large portion of the Company's annual fuel requirement is subject to fluctuation in commodity market prices. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts and utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. The strategy is designed to reduce the effects from market volatility through agreements with staggered expiration dates, volume options and varied pricing mechanisms. The adoption and implementation of the FAM, effective January 1, 2009, has further helped NSPI manage this risk.

Coal/Petroleum Coke

A substantial portion of NSPI's coal and petroleum coke ("petcoke") supply comes from international suppliers, which was contracted at or near the market prices prevailing at the time of contract. The Company has entered into fixed-price and index price contractual arrangements for coal with several suppliers as part of the fuel procurement portfolio strategy. All index priced contractual arrangements are matched with a corresponding financial instrument to fix the price. The approximate percentage of coal and petcoke requirements contracted as at December 31, 2011 are as follows:

- 2012 – 94 percent
- 2013 – 32 percent
- 2014 – 15 percent

Heavy Fuel Oil

NSPI manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options, and forward contracts. For 2012 and 2013, NSPI currently does not have heavy fuel oil hedging requirements due to favourable natural gas pricing.

Natural Gas

NSPI has entered into multi-year contracts to purchase approximately 38,400 mmbtu of natural gas per day in 2012, and 20,100 mmbtu of natural gas per day in 2013. Volumes exposed to market prices are managed using financial instruments where the fuel is required for NSPI's generation; and the balance is sold against market prices when available for resale. As at December 31, 2011, amounts of natural gas volumes that have been economically and/or financially hedged are approximately as follows:

- 2012 – 83 percent
- 2013 – 31 percent

Foreign Exchange Risk

NSPI enters into foreign exchange forward and swap contracts to limit the exposure of currency rate fluctuations related to fuel purchases. Currency forwards are used to fix the CAD cost to acquire USD, reducing exposure to currency rate fluctuations.

The risk due to fluctuation of the CAD against the USD for fuel purchases is measured and managed. In 2012, NSPI expects approximately 63 percent of its anticipated net fuel costs to be denominated in USD. Forward contracts to buy $256.0 million USD were in place as at December 31, 2011 at a weighted average rate of $0.9912, representing 81 percent of 2012's anticipated USD requirements. Forward contracts to buy $752.0 million USD in 2013 through 2016 at a weighted average rate of $1.0096 were in place at December 31, 2011. These contracts cover 60 percent of anticipated USD requirements in these years. As at December 31, 2011, there were no fuel-related foreign exchange swaps outstanding.

Commercial Relationships Risk

For the year ended December 31, 2011, NSPI's five largest customers contributed approximately 13.3 percent (2010 – 14.7 percent) of electric revenues. The loss of a large customer could have a material effect on NSPI's operating revenues. NSPI works to mitigate this risk through the regulatory process.

NSPI's largest customer was granted creditor protection under the Companies' Creditors Arrangement Act ("CCAA"), and suspended operations in September 2011. This customer contributed approximately 6.0 percent (2010 – 7.9 percent) of NSPI's electric revenues for the year ended December 31, 2011. NSPI is working to recover an outstanding receivable owing from this customer through the CCAA claims process, including a claim for set-off against amounts owing from NSPI to the customer that exceeds the amount receivable. The 2012 General Rate Decision, approved by the UARB, provides for any unrecovered non-fuel electric charges in 2012 related to this customer to be deferred and recovered beginning in 2013.

Relationships with Employees

Certain NSPI employees are subject to a collective labour agreement which will expire on March 31, 2012. Approximately 52 percent of NSPI's full-time employees and term employees are represented by a local union affiliated with the International Brotherhood of Electrical Workers. NSPI seeks to manage this risk through ongoing discussions with the union.

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit assessments are conducted on all new customers and deposits are requested on any high risk accounts. The Company is also exposed to credit risk with counterparties to its derivatives. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation.

Weather Risk

Shifts in weather patterns affect electric sales volumes and associated revenues with increased volatility in the winter months attributed to heating loads. Extreme weather events generally result in increased operating costs associated with restoring power to customers. NSPI responds to significant weather event related outages according to its Emergency Services Restoration Plan.

Interest Rate Risk

The Company utilizes a combination of fixed and variable rate debt financing for operations and capital expenditures resulting in an exposure to interest rate risk. The Company seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt. Floating-rate debt is estimated to represent approximately 16 percent of total debt in 2012. The Company has no interest rate hedging contracts outstanding as at December 31, 2011.

Changes in Environmental Legislation

The Company is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters primarily related to its utility operations. Changes to climate change and air emissions standards could adversely affect utility operations.

In addition to imposing continuing compliance obligations, there are laws, regulations and permits authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is material to NSPI. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on NSPI.

Conformance with legislative and NSPI requirements are verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the 2011 and 2010 audits.

NSPI is committed to operating in a manner that is respectful and protective of the environment, and in full compliance with legal requirements and Company policy. NSPI has implemented this policy through development and application of environmental management systems.

Climate Change and Air Emissions

Greenhouse Gas Emissions

NSPI has stabilized, and in recent years, reduced greenhouse gas emissions. This has been achieved by energy efficiency and conservation programs, increased use of natural gas and the addition of new renewable energy sources to the generation portfolio.

Greenhouse gas emissions from NSPI facilities have been capped beginning in 2010 through to 2020. The regulations allow for multi-year compliance periods recognizing the variability in electricity supply sources and demand. Over the decade, the caps will be achieved by a combination of additional renewable generation, import of non-emitting energy, and energy efficiency and conservation.

In 2011, Environment Canada announced proposed regulations for a new national carbon dioxide framework for the electricity sector in Canada. These proposed regulations would apply to new coal-fired electricity generation units; and existing coal-fired electricity generation units that have reached the end of their deemed economic life of forty-five years after commissioning. These proposed regulations will be effective July 1, 2015. Nova Scotia's existing greenhouse gas regulations require reductions in NSPI's emissions similar to those reflected in the federal framework. NSPI is engaged with federal and provincial agencies in reviewing the implications of this federal framework and its alignment with its current operating plans under existing Nova Scotia regulations.

Renewable Energy

The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI’s generation mix. The target date for 5 percent of electricity to be supplied from post-2001 sources of renewable energy, owned by independent power producers, was extended to 2011 from 2010. The target for 2013, which requires an additional 5 percent of renewable energy, is unchanged.

On May 19, 2011 the Nova Scotia Government approved The Electricity Act (Amended) to facilitate the eligibility of energy from the Lower Churchill Project in Labrador as a resource for meeting Nova Scotia's renewable electricity targets. The amendment requires regulations to be developed that increase the percentage of renewable energy in the generation mix from the planned 25 percent in 2015, to 40 percent by 2020.

Mercury, Nitrogen Oxide and Sulphur Dioxide Emissions

NSPI completed a capital program to add sorbent injection to each of the seven pulverized fuel coal units in 2010 at a cost of $17.3 million. This was put in place to address planned reductions in mercury emissions limits, which are set out in the following table:

Year	Mercury Emissions Limit (kg)
2009	168
2010	110
2011 – 2012	100
2013	85
2014 – 2019	65
2020	35

Any mercury emission above 65 kg, between 2010 and 2013, must be offset by lower emissions in the 2014 to 2020 period.

NSPI completed its capital program of retrofitting low nitrogen oxide combustion firing systems on six of its seven pulverized fuel coal units in early 2009 at a cost of $23.3 million. NSPI now meets the nitrogen oxide emission cap of 21,365 tonnes per year established by the Nova Scotia Government effective 2010. These investments, combined with the purchasing of low sulphur coal, allows NSPI to meet the provincial air quality regulations.

NSPI will meet ever-reducing sulphur dioxide emission cap requirements through the use of a blend of net lower sulphur content solid fuel.

Compared to historical levels, NSPI will have reduced mercury emissions by 60 percent effective 2014, nitrogen oxide by 40 percent effective 2009 and sulphur dioxide by 50 percent effective 2010.

DISCLOSURE AND INTERNAL CONTROLS

The Company, under the supervision and participation of management, including the Chief Executive Officer and Chief Financial Officer, have designed as at December 31, 2011 disclosure controls and procedures (“DC&P”) and internal controls over financial reporting (“ICFR”) as those terms are defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings (“NI 52-109”).

Pursuant to Section 404(c) of the Sarbanes-Oxley Act of 2002 (“SOX”), as added by Section 989G of the Dodd-Frank Wall Street Reform and Consumer Protection Act, the requirement under Section 404(b) of SOX to file an auditor attestation report on an issuer’s ICFR does not apply with respect to any audit report prepared for an issuer that is neither an accelerated filer nor a large accelerated filer, as defined in Rule 12b-2 under the Exchange Act. NSPI is currently not an accelerated filer or a large accelerated filer and, therefore, is not required to file an attestation report on its ICFR. As previously noted, in December 2011, NSPI made the necessary filings to terminate its SEC reporting obligations.

The Chief Executive Officer and the Chief Financial Officer have caused to be evaluated under their supervision, with the assistance of company employees, the effectiveness of the Company’s DC&P and ICFR, and based on that evaluation, have concluded DC&P and ICFR were effective at December 31, 2011.

There have been no changes in NSPI’s ICFR during the period beginning on January 1, 2011 and ending on December 31, 2011, which have materially affected, or are reasonably likely to materially affect ICFR.

SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an on-going basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. Significant areas requiring the use of management estimates relate to rate-regulation, the determination of pension and other post-retirement employee benefits, unbilled electric revenues, asset retirement obligations, useful lives for depreciable assets and income taxes. Actual results may differ from these estimates.

Rate Regulation

NSPI's accounting policies are subject to examination and approval by the UARB. As a result, its rate-regulated accounting policies may differ from accounting policies for non-rate-regulated companies. These differences occur when the regulator renders its decisions on rate applications or other matters and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on the expectation of the future actions of the regulators.

If the regulator's future actions are different from the regulator's previous rulings, the timing and amount of the recovery of liabilities and refund of assets, recorded or unrecorded, could be significantly different from that reflected in the financial statements.

Pension and Other Post-Retirement Employee Benefits

The Company provides post-retirement benefits to employees, including defined benefit pension plans. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The benefit cost and accrued benefit obligation for employee future benefits included in annual compensation expenses are affected by employee demographics, including age, compensation levels, employment periods, contribution levels and earnings on plan assets.

Changes to the provision of the plan may also affect current and future pension costs. Benefit costs may also be affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation and benefit costs.

The pension plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

Consistent with US GAAP and NSPI's accounting policy, the Company amortizes the net actuarial gain or loss, which exceeds 10 percent of the greater of the projected benefit obligation/accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period, which is currently 9 years. NSPI's use of smoothed asset values further reduces the volatility related to the amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO. The discount rate used to determine benefit costs is based on high quality long-term Canadian corporate bonds. The discount rate is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year rounded to the nearest 25 basis points. For benefit cost purposes, NSPI's rate was 5.50 percent for 2011 (2010 – 6.50 percent).

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts. The benefit cost calculations assumed that plan assets would earn a rate of return of 7.00 percent for 2011 (2010 – 7.25 percent).

The reported benefit cost for 2011 for all defined benefit and defined contribution plans, based on management's best estimate assumptions, is $41.1 million. While there are numerous assumptions which are used to determine the benefit cost, the discount rate and asset return assumptions have an impact on the calculations.

The following shows the impact on 2011 benefit cost of a 25 basis point change (0.25 percent) in the discount rate and asset return assumptions:

	Increase 0.25%		Decrease 0.25%	
millions of Canadian dollars	**2011**	2010	**2011**	2010
Discount rate assumption	**$(3.5)**	$(3.0)	**$3.6**	$3.1
Asset return assumption	**$(1.8)**	$(1.7)	**$1.8**	$1.7

Unbilled Electric Revenues

Electric revenues are billed on a systematic basis over a one or two-month period. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and of related revenues earned but not yet billed. The unbilled electric revenues are estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses and applicable customer rates. Based on the extent of the estimates included in the determination of unbilled electric revenues, actual results may differ from the estimate. As at December 31, 2011, unbilled electric revenues were $88.5 million (2010 – $84.1 million) on a base of annual electric revenues of approximately $1.2 billion (2010 – $1.2 billion).

Asset Retirement Obligations

The Company recognizes an ARO if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation related to reclamation of land at the Company's thermal, hydro, combustion turbine sites, and disposal of polychlorinated biphenyls ("PCBs") in its transmission and distribution equipment using the Company's credit adjusted risk-free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives, and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. Any accretion expense not yet approved by the UARB is deferred to a regulatory asset in "Property, plant and equipment" and included in the next depreciation study.

Some transmission and distribution assets may have conditional AROs, which are required to be estimated and recorded as a liability. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at fair value when an amount can be determined. NSPI believes that it will continue to be able to recover ARO through rates. Accordingly, changes to the ARO, or cost recognition attributable to changes in the factors discussed above, should not impact the results of operations of the Company.

The key assumptions used to determine the ARO are as follows:

Asset	Credit-adjusted risk-free rate		Estimated undiscounted future obligation (millions of Canadian dollars)		Expected settlement date (number of years)	
	2011	2010	**2011**	2010	**2011**	2010
Thermal	**5.1 – 5.3%**	5.2 – 5.3%	**$142.8**	$258.9	**21 – 32**	10 – 29
Hydro	**5.1 – 5.3%**	5.2 – 5.3%	**127.6**	101.4	**20 – 50**	21 – 51
Wind	**5.1 – 5.2%**	5.2%	**27.4**	45.5	**17 – 24**	13 – 20
Combustion turbines	**5.1 – 5.3%**	5.2 – 5.3%	**8.3**	12.9	**5 – 34**	1 – 14
Transmission & distribution	**4.3 – 5.8%**	5.7%	**27.4**	21.6	**1 – 14**	1 – 15
			$333.5	$440.3		

As at December 31, 2011, AROs recorded on the balance sheet were $91.1 million (2010 – $138.7 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $333.5 million, which will be incurred between 2012 and 2062. The majority of these costs will be incurred between 2032 and 2047.

Property, Plant and Equipment

Property, plant and equipment represents 78 percent of total assets recognized on the Company's balance sheet. Included in "Property, plant and equipment" are the generation, transmission and distribution and other assets of the Company. Due to the magnitude of the Company's property, plant and equipment, changes in estimated depreciation rates can have a material impact on depreciation expense.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of assets are determined based on formal depreciation studies and are approved by the UARB.

On May 11, 2011, the UARB approved changes to NSPI's depreciation rates following NSPI's completion of a depreciation study and a settlement agreement with stakeholders. The overall impact on the average deprecation rate is immaterial. The new depreciation rates are effective January 1, 2012 as approved by the UARB in the 2012 General Rate Decision.

Income Taxes

Income taxes are determined based on the expected tax treatment of transactions recorded in the financial statements. In determining income taxes, tax legislation is interpreted, the likelihood that deferred tax assets will be recovered from future taxable income is assessed and assumptions about the expected timing of the reversal of deferred tax assets and liabilities are made. If interpretations differ from those of tax authorities or if the recovery of deferred tax assets or timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. The amount of any such increase or decrease cannot be reasonably estimated.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Future Accounting Pronouncements

Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, Accounting Standards Update ("ASU") Number ("No.") 2011-11

In December 2011, The Financial Accounting Standards Board ("FASB") issued an accounting standards update which requires companies to disclose gross information and net information about both instruments and transactions eligible for offset in the statement of financial positions and instruments and transactions subject to an agreement similar to a master netting arrangement to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU No. 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013 with required disclosures made retrospectively for all comparative periods presented. The Company is currently evaluating the impact that the adoption will have in the financial statements.

Other Comprehensive Income, ASU No. 2011-05

In June 2011, FASB issued an accounting standards update amending Accounting Standards Codification ("ASC") 220 to improve the comparability, consistency and transparency of comprehensive income reporting. The guidance requires that items of net income, items of other comprehensive income and total comprehensive income be presented in one continuous statement or two separate but consecutive statements. Items that are reclassified from other comprehensive income to net income must be presented separately on the face of the financial statements. ASU No. 2011-05 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Retrospective application of the new disclosures will be required for comparative periods. The adoption of this update will change the order in which certain financial statements are presented and provide additional detail on those financial statements where applicable, but will not have any other impact to the financial statements.

Subsequently in December 2011, FASB issued ASU No. 2011-12, *Deferral of the Effective Date for Amendments to Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05.* The amendments in ASU No. 2011-12 defer the changes in ASU No. 2011-05 that relate to the presentation of reclassification adjustments out of AOCL.

Fair Value Measurement, ASU No. 2011-04

In May 2011, FASB issued an accounting standards update amending ASC 820 to achieve common fair value measurement and disclosure requirements between USGAAP and International Financial Reporting Standards ("IFRS"). The amendments clarify the intent concerning the application of existing requirements and include some instances where a particular principle or requirement for measuring fair value or disclosing information related to fair value measurements has changed. ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The Company is currently evaluating the impact that the adoption will have in the financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of Canadian dollars	**Q4 2011**	Q3 2011	Q2 2011	Q1 2011	Q4 2010 (adjusted)	Q3 2010 (adjusted)	Q2 2010 (adjusted)	Q1 2010 (adjusted)
Total operating revenues	**$289.2**	$276.0	$299.0	$368.8	$303.2	$272.2	$273.2	$342.8
Net income attributable to common shareholders	**22.2**	21.0	16.7	63.6	19.9	18.6	15.5	65.2

Quarterly total operating revenues and net income attributable to common shareholders are affected by seasonality, with Q1 and Q4 the strongest periods, reflecting colder weather and fewer daylight hours at those times of year.

OPERATING STATISTICS (Unaudited)

FIVE-YEAR SUMMARY

Year Ended December 31	**2011**	2010	2009	2008	2007
Electric energy sales (GWh)					
Residential	**4,275**	4,147	4,228	4,179	4,145
Commercial	**3,102**	3,088	3,107	3,115	3,160
Industrial	**3,516**	3,908	3,642	4,144	4,191
Other	**313**	312	328	334	366
Total electric energy sales	**11,206**	11,455	11,305	11,772	11,862
Sources of energy (GWh)					
Thermal – coal	**6,848**	7,839	8,177	9,009	9,562
– oil	**35**	36	307	340	515
– natural gas	**2,430**	2,275	1,612	1,258	1,057
Hydro	**1,088**	992	1,063	1,065	909
Wind	**247**	25	2	2	2
Purchases – wind	**572**	355	150	148	161
– other renewables	**171**	171	151	170	151
– imports	**526**	471	630	571	342
Total generation and purchases	**11,917**	12,164	12,092	12,563	12,699
Losses and internal use	**711**	709	787	791	837
Total electric energy sold	**11,206**	11,455	11,305	11,772	11,862
Electric customers					
Residential	**446,379**	442,824	439,338	435,847	431,697
Commercial	**34,998**	34,864	34,678	34,509	34,266
Industrial	**2,462**	2,485	2,499	2,496	2,503
Other	**9,344**	9,256	9,153	9,062	9,572
Total electric customers	**493,183**	489,429	485,668	481,914	478,038
Capacity					
Generating nameplate capacity (MW)					
Coal fired	**1,243**	1,243	1,243	1,243	1,243
Dual fired	**350**	350	350	350	350
Gas turbines	**304**	304	304	304	304
Hydroelectric	**395**	395	395	395	395
Wind turbines	**82**	76	1	1	1
Independent power producers	**229**	186	137	85	85
	2,603	2,554	2,430	2,378	2,378
Total number of employees	**1,883**	1,900	1,865	1,791	1,740
km of transmission lines (69 kV and over)	**5,000**	5,000	5,000	5,000	5,000
km of distribution lines (25 kV and under)	**26,000**	26,000	26,000	26,000	25,000

THREE YEAR FINANCIAL SUMMARY (Unaudited)

For the year ended December 31 millions of Canadian dollars	2011	2010 (adjusted)	2009 (adjusted)
Statements of Income Information			
Operating revenues	**$1,233.0**	$1,191.4	$1,211.8
Operating expenses			
Fuel for generation and purchased power	**546.3**	578.6	525.8
Fuel for generation and purchased power – affiliates	**1.1**	8.1	(25.1)
Fuel adjustment	**(8.5)**	(99.0)	8.5
Operating, maintenance and general	**268.6**	245.8	223.9
Provincial grants and taxes	**38.7**	40.1	40.5
Depreciation and amortization	**187.2**	188.1	171.5
Total operating expenses	**1,033.4**	961.7	945.1
Income from operations	**199.6**	229.7	266.7
Other expenses, net	**8.9**	11.3	3.3
Interest expense, net	**104.2**	104.7	102.8
Income before provision for income taxes	**86.5**	113.7	160.6
Income tax (recovery) expense	**(44.9)**	(13.4)	40.3
Net income of Nova Scotia Power Inc.	**131.4**	127.1	120.3
Preferred stock dividends	**7.9**	7.9	9.5
Net income attributable to common shareholders	**$123.5**	$119.2	$110.8
Fuel for generation and purchased power - coal	**$298.2**	$338.5	$299.3
Fuel for generation and purchased power - oil	**6.2**	0.7	-
Fuel for generation and purchased power - natural gas	**148.2**	169.3	138.5
Purchased power	**94.8**	78.2	62.9
Total fuel for generation and purchased power	**$547.4**	$586.7	$500.7
Balance Sheets Information			
Current assets	**$551.4**	$491.9	$607.1
Property, plant and equipment, net of accumulated depreciation	**3,057.6**	2,949.5	2,519.4
Other assets			
Deferred income taxes	**-**	16.8	61.4
Derivative instruments	**28.6**	28.9	36.0
Regulatory assets	**173.0**	232.5	193.0
Intangibles, net of accumulated amortization	**73.6**	73.2	66.8
Other	**12.8**	11.9	10.1
Total assets	**$3,897.0**	$3,804.7	$3,493.8
Current liabilities	**359.8**	366.7	640.6
Long-term debt	**1,961.0**	1,949.1	1,410.3
Deferred income taxes	**23.8**	-	-
Derivative instruments	**13.0**	11.2	21.3
Regulatory liabilities	**29.3**	61.7	87.1
Asset retirement obligations	**91.1**	138.7	101.5
Pension and post-retirement liabilities	**420.0**	314.7	221.2
Other long-term liabilities	**4.5**	5.6	14.4
Redeemable preferred stock	**132.2**	132.2	132.2
Common stock	**1,034.7**	984.7	934.7
Accumulated other comprehensive loss	**(476.7)**	(365.7)	(256.1)
Retained earnings	**304.3**	205.8	186.6
Total liabilities and equity	**$3,897.0**	$3,804.7	$3,493.8
Statements of Cash Flow Information			
Cash provided by operating activities	**$272.3**	$317.3	$286.2
Cash used in investing activities	**(316.3)**	(542.5)	(272.6)
Cash provided by (used in) financing activities	**$43.7**	$225.2	$(13.3)

NOVA SCOTIA POWER INC.

Financial Statements

December 31, 2011 and 2010

MANAGEMENT REPORT

Management's Responsibility for Financial Reporting

The accompanying financial statements of Nova Scotia Power Inc. ("NSPI" or "the Company") and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. In preparation of these financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management represents that such estimates, which have been properly reflected in the accompanying financial statements, are based on careful judgements and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

NSPI maintains effective systems of internal accounting and administrative controls, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate, and that NSPI's assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit, Nominating & Corporate Governance Committee ("Committee").

The Committee is appointed by the Board, and its members are directors who are not officers or employees of NSPI. The Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the financial statements and the external auditors' report. The Committee reports its findings to the Board for consideration when approving the financial statements for issuance to the shareholders. The Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The financial statements have been audited by Grant Thornton LLP, the external auditors, in accordance with Canadian Generally Accepted Auditing Standards and the standards of the Public Company Accounting Oversight Board (United States). Grant Thornton LLP has full and free access to the Committee.

February 8, 2012

"Robert R. Bennett"
President and Chief Executive Officer

"Judy Steele, FCA"
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Nova Scotia Power Inc.

We have audited the accompanying financial statements of Nova Scotia Power Inc., which comprise the balance sheets as at December 31, 2011 and 2010, the statements of income, cash flows, comprehensive income, and changes in shareholders' equity for the years then ended and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

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

Auditor's responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Nova Scotia Power Inc .as at December 31, 2011 and 2010, and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Halifax, Canada	*"Grant Thornton LLP"*
February 8, 2012	Chartered accountants

Nova Scotia Power Inc.
Statements of Income
Years ended December 31

millions of Canadian dollars	2011	2010 (as adjusted – note 23)
Operating revenues	**$1,233.0**	$1,191.4
Operating expenses		
Fuel for generation and purchased power	**546.3**	578.6
Fuel for generation and purchased power – affiliates (note 21)	**1.1**	8.1
Fuel adjustment (note 3)	**(8.5)**	(99.0)
Operating, maintenance and general	**268.6**	245.8
Provincial grants and taxes	**38.7**	40.1
Depreciation and amortization	**187.2**	188.1
Total operating expenses	**1,033.4**	961.7
Income from operations	**199.6**	229.7
Other expenses, net (note 4)	**8.9**	11.3
Interest expense, net (note 5)	**104.2**	104.7
Income before provision for income taxes	**86.5**	113.7
Income tax recovery (note 6)	**(44.9)**	(13.4)
Net income of Nova Scotia Power Inc.	**131.4**	127.1
Preferred stock dividends	**7.9**	7.9
Net income attributable to common shareholders	**$123.5**	$119.2

The accompanying notes are an integral part of these financial statements.

Nova Scotia Power Inc.
Balance Sheets
As at December 31

millions of Canadian dollars	2011	2010 (as adjusted – note 23)
Assets		
Current assets		
Cash	-	$0.3
Receivables, net (note 7)	**$208.6**	192.5
Income taxes receivable	**40.0**	34.3
Inventory (note 8)	**155.8**	154.2
Derivative instruments (note 15)	**15.9**	31.0
Regulatory assets (note 14)	**124.7**	71.8
Prepaid expenses	**6.4**	6.0
Other current assets	-	1.8
Total current assets	**551.4**	491.9
Property, plant and equipment, net of accumulated depreciation of $2,248.0 and $2,153.1, respectively (note 9)	**3,057.6**	2,949.5
Other assets		
Deferred income taxes (note 6)	-	16.8
Derivative instruments (note 15)	**28.6**	28.9
Regulatory assets (note 14)	**173.0**	232.5
Intangibles, net of accumulated amortization of $38.7 and $33.5, respectively	**73.6**	73.2
Other	**12.8**	11.9
Total other assets	**288.0**	363.3
Total assets	**$3,897.0**	$3,804.7

The accompanying notes are an integral part of these financial statements.

Nova Scotia Power Inc.
Balance Sheets – Continued
As at December 31

millions of Canadian dollars	2011	2010 (as adjusted – note 23)
Liabilities and Equity		
Current liabilities		
Short-term debt (note 10)	**$63.9**	$48.3
Current portion of long-term debt (note 11)	**-**	0.1
Accounts payable	**144.2**	157.9
Due to related parties (note 21)	**1.3**	6.2
Deferred income taxes (note 6)	**8.3**	3.4
Derivative instruments (note 15)	**33.3**	23.0
Regulatory liabilities (note 14)	**23.2**	52.4
Pension and post-retirement liabilities (note 17)	**8.3**	8.2
Other current liabilities (note 12)	**77.3**	67.2
Total current liabilities	**359.8**	366.7
Long-term liabilities		
Long-term debt (note 11)	**1,961.0**	1,949.1
Deferred income taxes (note 6)	**23.8**	-
Derivative instruments (note 15)	**13.0**	11.2
Regulatory liabilities (note 14)	**29.3**	61.7
Asset retirement obligations (note 13)	**91.1**	138.7
Pension and post-retirement liabilities (note 17)	**420.0**	314.7
Other long-term liabilities	**4.5**	5.6
Total long-term liabilities	**2,542.7**	2,481.0
Commitments and contingencies (note 18)		
Redeemable preferred stock, $25 par value; unlimited First Preferred Series D shares authorized; 5.4 million shares issued and outstanding (note 19)	**132.2**	132.2
Equity		
Common stock, no par value; unlimited shares authorized; 117.2 million shares and 112.2 million shares issued and outstanding, respectively	**1,034.7**	984.7
Accumulated other comprehensive loss	**(476.7)**	(365.7)
Retained earnings	**304.3**	205.8
Total equity	**862.3**	824.8
Total liabilities and equity	**$3,897.0**	$3,804.7

The accompanying notes are an integral part of these financial statements.

Approved on behalf of the Board of Directors

"James D. Eisenhauer" ***"Robert R. Bennett"***

Chairman **President and Chief Executive Officer**

Nova Scotia Power Inc.
Statements of Cash Flows
Years Ended December 31

millions of Canadian dollars	2011	2010 (as adjusted – note 23)
Operating activities		
Net income of Nova Scotia Power Inc.	**$131.4**	$127.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**200.5**	202.9
Allowance for equity funds used during construction	**(7.8)**	(8.3)
Deferred income taxes, net	**0.9**	29.7
Net change in pension and post-retirement obligations	**(5.6)**	(16.2)
Fuel adjustment	**(15.2)**	(102.8)
Net changes in fair value of derivative instruments	**1.1**	18.6
Other operating activities, net	**2.2**	1.8
Changes in non-cash working capital:		
Receivables, net	**(16.1)**	78.4
Income taxes receivable	**(5.7)**	(37.6)
Inventory	**(1.6)**	11.4
Prepaid expenses	**(0.4)**	(0.3)
Accounts payable	**(13.7)**	6.2
Due to related parties	**(4.9)**	4.6
Other current liabilities	**7.2**	1.8
Net cash provided by operating activities	**272.3**	317.3
Investing activities		
Additions to property, plant and equipment	**(297.0)**	(518.0)
Additions to intangibles	**(5.6)**	(10.0)
Allowance for borrowed funds used during construction	**(8.4)**	(8.9)
Retirement spending, net of salvage	**(5.3)**	(5.6)
Net cash used in investing activities	**(316.3)**	(542.5)
Financing activities		
Change in short-term debt, net	**27.4**	90.4
Proceeds from long-term debt	**-**	300.0
Retirement of long-term debt	**-**	(100.0)
Issuance of common stock	**50.0**	50.0
Preferred stock dividends	**(7.9)**	(7.9)
Common stock dividends	**(25.0)**	(100.0)
Other financing activities	**(0.8)**	(7.3)
Net cash provided by financing activities	**43.7**	225.2
Net change in cash	**(0.3)**	-
Cash, beginning of period	**$0.3**	0.3
Cash, end of period	**-**	$0.3
Supplemental disclosure of cash paid (received):		
Interest	**$120.2**	$115.5
Income and capital taxes	**$(40.5)**	$(4.4)

The accompanying notes are an integral part of these financial statements.

Nova Scotia Power Inc.
Statements of Comprehensive Income
Years Ended December 31

millions of Canadian dollars	2011	2010 (as adjusted – note 23)
Net income of Nova Scotia Power Inc.	**$131.4**	$127.1
Other comprehensive loss		
Net change in unrecognized pension and post-retirement benefit costs	**(111.0)**	(109.6)
Comprehensive income	**$20.4**	$17.5

The accompanying notes are an integral part of these financial statements.

Nova Scotia Power Inc.
Statements of Changes in Equity
Years Ended December 31

millions of Canadian dollars	Common Stock	Accumulated Other Comprehensive Loss ("AOCL")	Retained Earnings	Total Equity
2011				
Balance, December 31, 2010 (as adjusted – note 23)	$984.7	$(365.7)	$205.8	$824.8
Net income of Nova Scotia Power Inc.	-	-	131.4	131.4
Other comprehensive loss	-	(111.0)	-	(111.0)
Issuance of common stock	50.0	-	-	50.0
Cash dividends declared on common stock	-	-	(25.0)	(25.0)
Cash dividends declared on preferred stock ($1.475 per share)	-	-	(7.9)	(7.9)
Balance, December 31, 2011	$1,034.7	$(476.7)	$304.3	$862.3
2010 (as adjusted – note 23)				
Balance, December 31, 2009	$934.7	$(256.1)	$186.6	$865.2
Net income of Nova Scotia Power Inc.	-	-	127.1	127.1
Other comprehensive loss	-	(109.6)	-	(109.6)
Issuance of common stock	50.0	-	-	50.0
Dividends declared on common stock	-	-	(100.0)	(100.0)
Cash dividends declared on preferred stock ($1.475 per share)	-	-	(7.9)	(7.9)
Balance, December 31, 2010	$984.7	$(365.7)	$205.8	$824.8

The accompanying notes are an integral part of these financial statements.

Nova Scotia Power Inc.
Notes to the Financial Statements

As at December 31, 2011 and 2010

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies of Nova Scotia Power Inc. are as follows:

A. Nature of Operations

Nova Scotia Power Inc. ("NSPI" or the "Company") is a fully-integrated regulated electric utility and the primary electricity supplier in Nova Scotia, Canada, providing generation, transmission and distribution services to approximately 493,000 customers. NSPI is a public utility as defined under the Public Utilities Act of Nova Scotia (the "Act") and is subject to regulation by the Nova Scotia Utility and Review Board ("UARB"). The Company's accounting policies are subject to examination and approval of the UARB.

B. Basis of Presentation

Effective January 1, 2011, NSPI changed the basis of presentation of its financial statements (including the application of rate-regulated accounting policies) from Canadian Generally Accepted Accounting Principles ("CGAAP") to United States Generally Accepted Accounting Principles ("USGAAP").

These financial statements are prepared and presented in accordance with USGAAP and the rules and regulations of the United States Securities and Exchange Commission ("SEC") for Annual Reports. These financial statements should be read in conjunction with note 23, detailing the CGAAP to USGAAP transition and reconciliation information.

In the opinion of management, these financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of NSPI.

All dollar amounts are presented in Canadian dollars.

C. Use of Management Estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an on-going basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. Significant estimates are included in unbilled revenue, allowance for doubtful accounts, inventory, valuation of derivative instruments, depreciation, amortization, regulatory assets and regulatory liabilities (including the determination of the current portion), income taxes (including deferred income taxes), pension and post-retirement benefits, asset retirement obligations ("AROs") and contingencies. Actual results may differ significantly from these estimates.

D. Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third party regulator; are designed to recover the costs of providing the regulated products or services; and it is reasonable to assume rates are set at levels such that the costs can be charged to and collected from customers.

Regulatory assets represent incurred costs that have been deferred because it is probable that they will be recovered through future rates collected from customers. Management believes that existing regulatory assets are probable of recovery either because the Company received specific approval from the UARB, or due to regulatory precedent set for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

For regulatory assets and liabilities that are amortized, the amortization is approved by the UARB.

E. Foreign Currency Translation

Monetary assets and liabilities, denominated in foreign currencies, are converted to Canadian dollars at rates of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date are included in income.

F. Revenue Recognition

Operating revenues are recognized when electricity is delivered to customers or when products are delivered and services are rendered. Revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity are recognized at rates approved by the UARB and recorded based on meter readings and estimates, which occur on a systematic basis throughout each month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The accuracy of the unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

G. Research and Development Costs

Research and development costs are expensed as incurred.

H. Employee Benefits

The costs of the Company's pension and other post-employment benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined benefit and other post-employment plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in AOCL.

I. Receivables and Allowance for Doubtful Accounts

Customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity sales for bi-monthly customers are 30 days and for monthly customers, payment terms are 20 days. A late payment fee of 1.5 percent may be assessed on account balances after the due date.

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit risk assessments are conducted on all new customers and deposits are requested on any high risk accounts. The Company also maintains provisions for potential credit losses, which are assessed on a regular basis.

Management estimates uncollectible accounts receivable after considering historical loss experience, current events and the characteristics of existing accounts. Provisions for losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

J. Inventory

Inventory, consisting of fuel and materials, is measured at the lower of cost or market. Fuel cost is determined using the weighted average method and material cost is determined using the average costing method. Fuel and materials are charged to inventory when purchased and then expensed or capitalized, as appropriate, using the weighted average cost method for fuel and average costing method for materials.

K. Property, Plant and Equipment

Property, plant and equipment are recorded at original cost, including allowance for funds used during construction ("AFUDC"), net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units of property, plant and equipment are included in "Property, plant and equipment". When units of regulated property, plant and equipment are replaced, renewed or retired, their cost plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation with no gain or loss reflected in income.

Normal maintenance projects are expensed as incurred. Planned major maintenance projects that do not increase the overall life of the related assets are expensed. When a cost increases the life or value of the underlying asset, the cost is capitalized.

L. Capitalization Policy

The cost of property, plant and equipment represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property, AROs and overhead directly attributable to the capital project. Overhead includes costs related to support functions, employee benefits, insurance, inventory, and fleet operating and maintenance.

M. Allowance for Funds Used During Construction

AFUDC represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment. As approved by the UARB, the Company includes an equity cost component in AFUDC in addition to a charge for borrowed funds. AFUDC is a non-cash item; cash is realized under the rate-making process over the service life of the related property, plant and equipment through future revenues resulting from a higher rate base and recovery of higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to "Interest expense, net", while the equity component is included in "Other expenses, net". AFUDC is calculated using a weighted average cost of capital, as per the method of calculation approved by the UARB, and is compounded semi-annually. The annual AFUDC rate for 2011 is 7.87 percent (2010 – 7.96 percent), comprised a debt portion of 4.06 percent (2010 – 4.15 percent) and an equity portion of 3.81 percent (2010 – 3.81 percent).

N. Depreciation

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets, including assets under capital leases, in each category. The service lives of assets are determined based on formal depreciation studies and are approved by the UARB.

The estimated useful lives, in years, for each major category of property, plant and equipment consist of the following:

Generation	20 to 131
Transmission	39 to 65
Distribution	24 to 75
General plant	7 to 40

O. Intangible Assets

Intangible assets consist primarily of land rights and computer software with definite lives. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of assets are determined based on formal depreciation studies and are approved by the UARB.

The estimated useful lives, in years, for each major category of intangibles with definite lives consist of the following:

Land rights	50 to 80
Computer software	10

The estimated aggregate amortization expense for each of the five succeeding fiscal years is $1.0 million for land rights and $3.3 million for Computer software.

P. Asset Impairment

Long-lived assets and intangibles are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. NSPI bases its evaluation of long-lived assets and intangibles on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors. If the sum of the undiscounted cash flows expected from an asset is less than the carrying value of the asset, the asset is written down to fair value.

There were no material asset impairments of these assets for the years ended December 31, 2011 and 2010.

Q. Debt Financing Costs

The Company capitalizes the external costs of obtaining debt financing and includes them in “Other” as part of “Other assets” on the Balance Sheet; premiums and discounts are netted against “Long-term debt” on the Balance Sheet. The deferred charges are amortized over the life of the related debt on an effective interest basis and included in “Interest expense, net”.

R. Income Taxes and Investment Tax Credits

NSPI recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheet and their respective tax bases using enacted tax rates in effect for the year in which the differences are expected to reverse. NSPI recognizes the effect of income tax positions only when it is more likely than not that they will be realized. If management subsequently determines that it is likely that some or all of a deferred income tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

Investment tax credits arise as a result of incurring qualifying scientific research and development expenditures and are recorded as a reduction to income tax expense in the current or future periods to the extent that realization of such benefit is more likely than not.

NSPI classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively.

S. Asset Retirement Obligations

An ARO is recognized if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation using the Company's credit adjusted risk-free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives, and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. Accretion expense is included as part of "Depreciation and amortization". Any accretion expense not yet approved by the UARB is deferred to a regulatory asset in "Property, plant and equipment" and included in the next depreciation study.

Some transmission and distribution assets may have conditional AROs, which are required to be estimated and recorded as a liability. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at fair value when an amount can be determined.

T. Derivatives and Hedging Activities

NSPI's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management practices are overseen by the Board of Directors. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operations.

The Company manages its exposure to normal operating and market risks relating to commodity prices, and foreign exchange using financial instruments consisting mainly of foreign exchange forwards and swaps, and coal, oil and gas options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. Collectively these contracts are considered "derivatives".

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exception. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty credit worthy. NSPI continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exception where the criteria are no longer met.

Derivatives entered into by NSPI that are documented as economic hedges, and for which the NPNS exception has not been taken, receive regulatory deferral as approved by the UARB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized when the derivatives settle. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates through the FAM

Derivatives that do not meet any of the above criteria are designated as HFT derivatives and are recorded on the balance sheet at fair value, with changes normally recorded in net income of the period. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

NSPI classifies gains and losses on derivatives as a component of fuel for generation and purchased power, other expenses, inventory and property, plant and equipment, depending on the nature of the item being economically hedged. Cash flows from derivative activities are presented in the same category as the item being hedged within operating or investing activities on the Statements of Cash Flows.

U. Fair Value Measurement

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exception (refer to notes 15 and 16). Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arms-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information including the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. The Company uses a fair value hierarchy, based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the highest.

The three levels of the fair value hierarchy are defined as follows:

Level 1 Valuations - Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 Valuations - Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 Valuations - Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally-developed inputs. NSPI's primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

V. Variable Interest Entities

The Company performs ongoing analysis to assess whether it holds any variable interest entities ("VIEs"). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements and jointly-owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where NSPI is not deemed the primary beneficiary, the VIE is not recorded in the Company's financial statements.

The Company holds a variable interest in Renewable Energy Services Ltd. ("RESL"), a VIE for which it was determined that NSPI was not the primary beneficiary since it does not have the controlling financial interest of RESL. The Company has provided a $23.5 million guarantee with no set term for the indebtedness of RESL under a loan agreement between RESL and a third party lender, in support of which NSPI holds a security interest in all present and future assets of RESL. The guarantee arose in conjunction with NSPI's participation in a wind energy project at Point Tupper, Nova Scotia, which is being operated by RESL. Under a purchased power agreement, NSPI purchases, at a fixed price, 100 percent of the power generated by the project. A default by RESL, under its loan agreement, would require NSPI to make payment under the guarantee. As at December 31, 2011, RESL's indebtedness under the loan agreement was $21.9 million (2010 – $23.1 million), and NSPI has not recorded a liability in relation to the guarantee.

The Company has also identified certain long-term purchase power agreements that could be defined as variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

For the year ended December 31, 2011, the Company has not identified any new VIEs.

W. Derivative Positions and Cash Collateral

Derivatives, as reflected on the Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in “Receivables, net” and obligations to return cash collateral are recognized in “Accounts payable”.

2. FUTURE ACCOUNTING PRONOUNCMENTS

Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, Accounting Standards Update (“ASU”) Number (“No.”) 2011-11

In December 2011, The Financial Accounting Standards Board (“FASB”) issued an accounting standards update which requires companies to disclose gross information and net information about both instruments and transactions eligible for offset in the statement of financial positions and instruments and transactions subject to an agreement similar to a master netting arrangement to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU No. 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013 with required disclosures made retrospectively for all comparative periods presented. The Company is currently evaluating the impact that the adoption will have in the financial statements.

Other Comprehensive Income, ASU No. 2011-05

In June 2011, FASB issued an accounting standards update amending Accounting Standards Codification (“ASC”) 220 to improve the comparability, consistency and transparency of comprehensive income reporting. The guidance requires that items of net income, items of other comprehensive income and total comprehensive income be presented in one continuous statement or two separate but consecutive statements. Items that are reclassified from other comprehensive income to net income must be presented separately on the face of the financial statements. ASU No. 2011-05 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Retrospective application of the new disclosures will be required for comparative periods. The adoption of this update will change the order in which certain financial statements are presented and provide additional detail on those financial statements where applicable, but will not have any other impact to the financial statements.

Subsequently in December 2011, FASB issued ASU No. 2011-12, *Deferral of the Effective Date for Amendments to Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05.* The amendments in ASU No. 2011-12 defer the changes in ASU No. 2011-05 that relate to the presentation of reclassification adjustments out of AOCL.

Fair Value Measurement, ASU No. 2011-04

In May 2011, FASB issued an accounting standards update amending ASC 820 to achieve common fair value measurement and disclosure requirements between USGAAP and International Financial Reporting Standards (“IFRS”). The amendments clarify the intent concerning the application of existing requirements and include some instances where a particular principle or requirement for measuring fair value or disclosing information related to fair value measurements has changed. ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The Company is currently evaluating the impact that the adoption will have in the financial statements.

3. FUEL ADJUSTMENT

The fuel adjustment related to the fuel adjustment mechanism ("FAM") includes the effect of fuel costs in both the current and two preceding years, specifically, and as detailed in the table below:

- The difference between actual fuel costs and amounts recovered from customers in the current year. This amount, net of the incentive component, is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities".
- The recovery from (rebate to) customers of under (over) recovered fuel costs from prior years.

The fuel adjustment for the years ending December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Under recovery of current year fuel costs	**$(35.1)**	$(76.6)
Recovery from (rebate to) customers of prior years' fuel costs	**26.6**	(22.4)
Fuel adjustment	**$(8.5)**	$(99.0)

The Company has recognized a deferred income tax expense related to the fuel adjustment based on NSPI's enacted statutory tax rate. As at December 31, 2011, NSPI's deferred income tax liability related to the FAM was $29.0 million (2010 - $29.2 million).

The FAM regulatory asset includes amounts recognized as a fuel adjustment, associated interest that is included in "Interest expense, net", and the application of the 2010 deferral of tax benefits (see Regulatory Matters, Note 14). The following table shows the balance sheet classification of the various components of the FAM balances as at December 31:

millions of Canadian dollars	**2011**	2010
Current regulatory asset	**$69.0**	$27.2
Long-term regulatory asset	**24.7**	65.7
FAM regulatory asset	**$93.7**	$92.9
Current deferred income tax liability	**$(21.4)**	$(8.8)
Long-term deferred income tax liability	**(7.6)**	(20.4)
FAM deferred income tax liability	**$(29.0)**	$(29.2)

4. OTHER EXPENSES, NET

Other expenses, net for the years ended December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Allowance for equity funds used during construction	**$(7.8)**	$(8.3)
Amortization of defeasance costs	**12.1**	12.1
Foreign exchange gains	**-**	(0.4)
Foreign exchange losses recovered through the FAM	**5.2**	9.4
Other	**(0.6)**	(1.5)
	$8.9	$11.3

5. INTEREST EXPENSE, NET

Interest expense, net for the years ended December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Interest on debt (1)	**$119.7**	$112.4
Interest revenue	**(10.0)**	(4.1)
Allowance for borrowed funds used during construction	**(8.4)**	(8.9)
Other	**2.9**	5.3
	$104.2	$104.7

(1) Interest on debt includes amortization of debt financing costs, premiums and discounts.

6. INCOME TAXES

The income tax provision, for the years ended December 31, differs from that computed using the statutory rates for the following reasons:

millions of Canadian dollars		2011		2010
Income before provision for income taxes	**$86.5**		$113.7	
Income taxes, at statutory rates	**28.1**	**32.5%**	38.7	34.0%
Deferred income taxes on regulated income recorded as regulatory assets	**(45.7)**	**(52.8)%**	(53.9)	(47.4)%
Change in estimate of prior year expected benefit of tax deductions	**(25.2)**	**(29.1)%**	-	-
Non-deductible regulatory amortization	**5.5**	**6.3%**	11.8	10.4%
Reduction in FAM regulatory asset	**(4.7)**	**(5.4)%**	-	-
Recovery of prior year income taxes	**(1.7)**	**(2.0)%**	(4.7)	(4.1)%
Other	**(1.2)**	**(1.4)%**	(5.3)	(4.7)%
Income tax recovery	**$(44.9)**	**(51.9)%**	$(13.4)	(11.8)%

The 2011 statutory income tax rate of 32.5 percent (2010 – 34.0 percent) represents the combined Canadian federal and Nova Scotia provincial income tax rates, which are the relevant tax jurisdictions for NSPI.

The following reflects the composition of taxes on income from continuing operations for the years ended December 31:

millions of Canadian dollars	2011	2010
Income tax recovery – current	**$(45.8)**	$(43.1)
Income tax expense – deferred	**0.9**	29.7
Income tax recovery	**$(44.9)**	$(13.4)

The deferred income tax assets and liabilities as at December 31 consisted of the following:

millions of Canadian dollars	2011	2010
Deferred income tax assets:		
Intangibles	**$23.5**	$23.6
Asset retirement obligations	**40.9**	62.4
Pension and other post-retirement liabilities	**192.4**	146.7
Tax loss carry forwards	**17.3**	17.0
Other	**28.3**	21.0
Total deferred income tax assets before valuation allowance	**302.4**	270.7
Valuation allowance	**(13.4)**	(13.3)
Total deferred income tax assets after valuation allowance	**$289.0**	$257.4
Deferred income tax liabilities:		
Property, plant and equipment	**$255.0**	$178.1
Regulatory assets (deferral of FAM)	**29.0**	29.2
Regulatory assets (unamortized defeasance costs)	**17.8**	19.2
Other	**19.3**	17.5
Total deferred income tax liabilities	**$321.1**	$244.0
Balance Sheet presentation		
Long-term deferred income tax assets	**-**	$16.8
Current deferred income tax liabilities	**$(8.3)**	(3.4)
Long-term deferred income tax liabilities	**(23.8)**	-
Net deferred income tax (liabilities) assets	**$(32.1)**	$13.4

The offset to substantially all of the net deferred income tax assets and liabilities noted above has been recorded as a regulatory asset or regulatory liability. These amounts include a gross up to reflect the income tax associated with future revenues required to fund these deferred income tax liabilities, and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets.

In Q4 2011, NSPI modified its estimate of the expected tax benefit of tax deductions, electing to amend its tax returns for the years 2006 through 2009. This resulted in a $23.3 million reduction in income tax expense and a $3.0 million increase in interest revenue, recorded in the quarter. This change in accounting estimate has been accounted for on a prospective basis.

In Q4 2010, NSPI revised its estimate of the 2010 expected benefit from accelerated tax deductions, resulting in a $7.2 million reduction in income tax expense.

The following table summarizes as at December 31, 2011 the net operating loss ("NOL") and capital loss carryovers and the associated carryover periods, and the valuation allowances for amounts which NSPI has determined that realization is uncertain:

millions of Canadian dollars	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
NOL	$3.9	-	$3.9	2028-2030
Capital loss	13.4	$13.4	-	Indefinite
Total	$17.3	$13.4	$3.9	

As at December 31, 2011, NSPI had a gross NOL carryover of $12.5 million, and gross capital loss carryover of $59.5 million.

Considering all evidence regarding the utilization of the Company's deferred income tax assets, it has been determined that NSPI is more-likely-than-not to realize all recorded deferred income tax assets, except for the capital loss noted above. The only valuation allowance recorded as at December 31, 2011 is related to the capital loss carryover.

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

millions of Canadian dollars	**2011**	2010
Balance, January 1	**$12.3**	$11.8
Increases due to tax positions related to prior year	**0.3**	-
Increases due to tax positions related to current year	**1.7**	2.1
Decreases due to settlements with taxing authorities	**(1.1)**	-
Decreases due to expiration of statute of limitations	**(1.6)**	(1.6)
Balance, December 31	**$11.6**	$12.3

The total amount of unrecognized tax benefits as at December 31, 2011 was $11.6 million (2010 – $12.3 million) which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits as at December 31, 2011 was $1.3 million (2010 - $1.3 million). No penalties have been accrued. In the next twelve months, it is reasonable that $2.1 million of unrecognized tax benefits may be recognized due to statute expirations or settlement agreements with taxing authorities.

NSPI files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. As at December 31, 2011, NSPI's tax years still open to examination by taxing authorities include 2006 and subsequent years. With few exceptions, NSPI is no longer subject to examination for years prior to 2006.

7. RECEIVABLES, NET

Receivables, net as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Customer accounts receivable – billed	**$97.3**	$74.0
Customer accounts receivable – unbilled	**106.5**	107.8
Total customer accounts receivable	**203.8**	181.8
Allowance for doubtful accounts	**(7.6)**	(2.5)
Customer accounts receivable, net	**196.2**	179.3
Other	**12.4**	13.2
	$208.6	$192.5

8. INVENTORY

Inventory as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Fuel	**$126.2**	$125.9
Materials	**29.6**	28.3
	$155.8	$154.2

9. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Generation	**$2,785.5**	$2,727.4
Transmission	**659.9**	598.5
Distribution	**1,221.2**	1,178.7
General plant and other	**353.5**	318.8
Total cost	**5,020.1**	4,823.4
Less: Accumulated depreciation	**(2,248.0)**	(2,153.1)
	2,772.1	2,670.3
Construction work in progress	**285.5**	279.2
Net book value	**3,057.6**	2,949.5

For the year ended December 31, 2011, AFUDC of $16.2 million (2010 – $17.2 million) was capitalized to "Property, plant and equipment".

As a result of regulator-approved accounting policies and depreciation rates, NSPI defers certain costs within "Property, plant and equipment" that would not otherwise be deferred in the absence of rate-regulation. Cumulative differences between items recognized for rate regulatory purposes and applicable accounting standards including depreciation rates, AFUDC and overhead costs cannot be separately determined. Cumulative amounts related to asset retirement obligations and the associated accretion expense were $17.1 million as at December 31, 2011 (2010 – $15.2 million).

10. SHORT-TERM DEBT

NSPI's short-term borrowings consist of commercial paper issuances and advances on the revolving credit facility. Short-term debt and the related weighted-average interest rate as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	**Weighted-average interest rate**	2010	**Weighted-average interest rate**
Advances on the revolving credit facility (1)	**$4.6**	**3.25%**	$1.6	3.50%
Commercial paper (re-classed from long-term debt) (2)	**59.3**	**1.08%**	46.7	1.07%
Short-term debt	**$63.9**		$48.3	

(1) Advances on the long-term revolving credit facility (note 11) can be made by way of overdraft on accounts for up to $50 million.
(2) Commercial paper is backed by a revolving credit facility which matures in 2015. NSPI has the ability to refinance commercial paper on a long-term basis; however amounts expected to be paid through working capital are classified as short-term debt. All other drawings are classified as long-term debt (note 11).

11. LONG-TERM DEBT

NSPI's long-term debt includes the issuances detailed below. Medium-term notes and debentures are issued under trust indentures at fixed interest rates and are unsecured unless noted below. Also included is commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year. Long-term debt as at December 31 consisted of the following:

millions of Canadian dollars	Stated Interest Rate	Effective Interest Rate	Maturity	**2011**	2010
Commercial Paper (1)	-	1.08%	4 year renewal	**$312.8**	$288.4
Medium-term notes					
Series F	8.85%	8.21%	2025	**125.0**	125.0
Series I	8.40%	8.43%	2015	**70.0**	70.0
Series L	8.30%	8.96%	2036	**60.0**	60.0
Series M (2)	8.50%	7.76%	2026	**40.0**	40.0
Series N	7.60%	7.57%	2097	**50.0**	50.0
Series P	6.28%	6.28%	2029	**40.0**	40.0
Series R	7.45%	7.51%	2031	**75.0**	75.0
Series S	6.95%	7.12%	2033	**200.0**	200.0
Series T	5.75%	6.09%	2013	**300.0**	300.0
Series V	5.67%	5.71%	2035	**150.0**	150.0
Series W	5.95%	6.01%	2039	**200.0**	200.0
Series X	5.61%	5.65%	2040	**300.0**	300.0
				$1,610.0	$1,610.0
Debentures - Series 3	9.75%	9.99%	2019	**95.0**	95.0
Capital lease obligations				**-**	0.1
Commercial Paper (re-classed to short-term debt) (1)				**(59.3)**	(46.7)
Unamortized debt premium – net				**2.5**	2.4
				1,961.0	$1,949.2
Amount due within one year				**-**	(0.1)
				$1,961.0	$1,949.1

(1) Commercial paper is backed by a revolving credit facility which matures in 2015. NSPI has the ability to refinance commercial paper on a long-term basis however amounts expected to be paid through working capital are classified as short-term debt (note 10). All other drawings are classified as long-term debt.
(2) Notes are extendable until 2056 at the option of the holders.

The Company's total long-term credit facility, outstanding borrowings and available capacity as at December 31 were as follows:

millions of Canadian dollars	Maturity	2011	2010
Revolving credit facility (1)	June 2015	**$500.0**	$600.0
Less:			
Borrowings under credit facility		**317.4**	290.0
Letters of credit issued inside the line of credit		**0.2**	0.3
Use of available facility		**$317.6**	$290.3
Available capacity under existing agreement		**$182.4**	$309.7

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $50 million and such advances are classified as short-term debt (note 10).

As at December 31, 2011 the credit facility has standby fees of 0.22% associated with the unused portion. The weighted average interest rate on outstanding debt as at December 31, 2011 was 1.24% (2010 – 1.15%).

Credit Facilities

In June 2010, NSPI entered into a three year revolving credit facility for $600 million with a syndicate of banks. In August 2011, NSPI reduced its committed syndicated revolving bank line of credit from $600 million to $500 million and the maturity of the facility was extended from June 2013 to June 2015. NSPI has an active commercial paper program for up to $400 million, of which outstanding amounts are 100 percent backed by the Company's bank line, which results in an equal amount of credit being considered drawn and unavailable.

Debt Covenants

NSPI's debt obligations contain covenants related to the amount of debt to capitalization as defined in certain agreements. In addition, other covenants and financial reporting obligations exist. Failure to comply with these covenants could result in an event of default, which if not cured or waived, could result in the acceleration of outstanding debt obligations. As at December 31, 2011, NSPI was in compliance with all respective financial covenants related to outstanding debt.

Debt shelf prospectus

In May 2011, NSPI filed an amendment to its amended and restated short form base shelf prospectus and an amendment to its prospectus supplement for medium-term notes (unsecured). These amendments increased the aggregate principal amount of debt securities and medium-term notes that may be offered from time to time under the short form base shelf prospectus and prospectus supplement from $500 million to $800 million. As at December 31, 2011, $300 million in medium-term notes have been issued under NSPI's short form base shelf prospectus and prospectus supplement since their initial filing in 2010.

Long-Term Debt Maturities

As at December 31, 2011, long-term debt maturities, including capital lease obligations, for each of the next five years and in aggregate thereafter are as follows:

Year of Maturity	millions of Canadian dollars
2012	-
2013	$300.0
2014	-
2015	323.5
2016	-
Greater than 5 years	1,335.0
	$1,958.5

12. OTHER CURRENT LIABILITIES

Other current liabilities as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Accrued charges	**$29.7**	$27.5
Accrued interest on long-term debt	**29.8**	29.8
Sales taxes payable	**12.0**	7.0
Dividends payable	**2.0**	2.0
Other	**3.8**	0.9
	$77.3	$67.2

13. ASSET RETIREMENT OBLIGATIONS

Asset Retirement Obligations ("ARO") mostly relate to the reclamation of land at the thermal, hydro, and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment. Certain hydro, transmission and distribution assets may have additional ARO that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the fair value of any related ARO cannot be made at this time.

The change in ARO for the years ended December 31 is as follows:

millions of Canadian dollars	**2011**	2010
Balance, January 1	**$138.7**	$101.5
Additions	**-**	32.1
Liabilities settled	**(0.9)**	(1.2)
Accretion included in depreciation expense	**3.7**	3.5
Accretion deferred to regulatory asset	**1.9**	2.1
Revisions in estimated cash flows	**(52.3)**	0.7
Balance, December 31	**$91.1**	$138.7

As at December 31, 2011 and 2010, some of the Company's transmission and distribution assets may have additional conditional ARO which are not recognized in the financial statements as the fair value of these obligations could not be reasonably estimated given there is insufficient information to do so. Management will continue to monitor these obligations and a liability will be recognized in the period in which an amount becomes determinable.

During Q2 2011, NSPI's estimated future cash flows with respect to ARO were updated to reflect the results of a settlement agreement with stakeholders which was approved by the UARB, following the completion of a depreciation study. The changes resulted from a change in estimates of retirement dates and future decommissioning costs. The new accretion rates are effective January 1, 2012.

14. REGULATORY MATTERS

The Company is a public utility as defined in the Act and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. The Company is not subject to a general annual rate review process, but rather participates in hearings held from time to time at the Company's or the UARB's request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's target regulated return on equity ("ROE") range for 2011 was 9.1 percent to 9.6 percent based on an actual, average regulated common equity component of up to 40 percent of regulated capitalization. NSPI has a FAM, which enables NSPI to seek recovery of fuel costs through regularly scheduled rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year. The FAM has an incentive component, whereby NSPI retains or absorbs 10 percent of the over or under recovered amount to a maximum of $5 million.

In May, 2011, NSPI filed a General Rate Application ("GRA") with the UARB requesting an average 7.3 percent rate increase across all customer classes effective January 1, 2012. In November, 2011, the UARB approved a settlement agreement between NSPI and customer representatives which resulted in an average rate increase of 5.1 percent for all customers, effective January 1, 2012. Rates were approved based on a 9.2 percent ROE, applied to a 37.5 percent common equity component with a target earnings range of 9.1 percent to 9.5 percent on maximum actual equity of 40 percent.

Regulatory Assets and Regulatory Liabilities

Regulatory assets represent incurred costs that have been deferred because it is probable that they will be recovered through future rates collected from customers. Management believes that existing regulatory assets are probable of recovery either because the Company received specific approval from the UARB, or due to regulatory precedent set for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

Regulatory assets and liabilities as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Regulatory assets		
FAM	**$93.7**	$92.9
Unamortized defeasance costs	**82.4**	94.6
Deferrals related to derivative instruments	**48.4**	40.4
Pre-2003 income tax and related interest	**42.0**	56.9
Deferred income tax regulatory asset	**16.0**	-
Deferral of income and capital taxes not included in Q1 2005 rates	**7.8**	10.0
Deferral of demand side management	**5.4**	7.5
Deferral of vegetation management	**2.0**	2.0
	$297.7	$304.3
Current	**$124.7**	$71.8
Long-term	**173.0**	232.5
Total regulatory assets	**$297.7**	$304.3
Regulatory liabilities		
Deferrals related to derivative instruments	**$45.6**	$64.1
Deferred income tax regulatory liability	**6.9**	35.5
2010 renewable tax benefits deferral	**-**	14.5
	$52.5	$114.1
Current	**$23.2**	$52.4
Long-term	**29.3**	61.7
Total regulatory liabilities	**$52.5**	$114.1

Fuel Adjustment Mechanism

As discussed in Note 3, the UARB approved the implementation of a FAM for NSPI effective January 1, 2009. The change in the FAM balance for the years ended December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Balance, January 1	**$92.9**	$(9.9)
Under recovery of current year fuel costs	**35.1**	76.6
(Recovery from) rebate to customers of prior years' fuel costs	**(26.6)**	22.4
Application of the deferral related to tax benefits from 2010	**(14.5)**	-
Interest revenue on FAM balance	**6.8**	3.8
Balance, December 31	**$93.7**	$92.9

Unamortized Defeasance Costs

Upon privatization in 1992, the Company became responsible for managing a portfolio of defeasance securities held in trust, which as at December 31, 2011, totaled $1.0 billion (2010 – $1.0 billion). The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB.

Deferrals Related to Derivative Instruments

NSPI defers changes in fair value of derivatives that are documented as economic hedges, and for which the NPNS exception has not been taken as a regulatory asset or liability as approved by the UARB. The gain or loss is recognized when the derivatives settle in fuel for generation and purchased power, other expenses, inventory or property, plant and equipment, depending on the nature of the item being economically hedged.

Pre-2003 Income Tax and Related Interest

NSPI has a regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers as a result of capital cost allowance deductions the Company claimed in its corporate income tax return that were disallowed in a Supreme Court decision. NSPI applied to the UARB to include recovery of these costs in customer rates. In February 2007, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

In January 2010, NSPI reached an agreement with stakeholders on its calculation of the Company's regulated ROE. The agreement provides the Company with flexibility in amortizing its pre-2003 income tax regulatory asset such that the Company has flexibility in recognizing additional amortization in current periods and reducing amortization in future periods. The approval of the 2012 General Rate Decision provided continuation of this flexibility. For the year ended December 31, 2011, NSPI recorded an additional discretionary $0.1 million (2010 - $4.8 million) of regulatory amortization expense.

Deferred Income Tax Regulatory Asset and Liability

NSPI recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns, in accordance with NSPI's rate-regulated accounting policy as approved by the UARB. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, NSPI recognizes a regulatory asset or liability.

Deferral of Income and Capital Taxes Not Included in Q1 2005 Rates

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. As a result, the Company deferred $16.7 million, consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes. The UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

Deferral of Demand Side Management

The UARB agreed to allow NSPI to defer up to $12.8 million of demand side management expenditures for the period January 1, 2008 through December 31, 2009, to be recovered in rates over six years commencing January 1, 2009.

Deferral of Vegetation Management

The UARB agreed to allow NSPI to defer $2.0 million in vegetation management spending in 2008 to be recovered in rates in a future period. The investment in vegetation management spending was part of a specific initiative to improve the reliability of service provided to customers. The UARB approved recovery of this regulatory asset over two years, commencing January 1, 2012.

2010 Renewable Tax Benefits Deferral

In 2010, the UARB granted NSPI approval to defer certain tax benefits related to renewable energy projects arising in 2010. In 2011, the UARB approved an agreement NSPI reached with stakeholders to apply the deferral against the FAM regulatory asset, which reduced the FAM regulatory asset effective January 1, 2011. The application of the deferral reduced the amount of the FAM balance outstanding with the reduction applied to the amount that would otherwise be recovered from customers in 2012.

15. DERIVATIVE INSTRUMENTS

The Company enters into forwards, swaps and option contracts as part of its risk management strategy to limit exposure to:

- commodity price fluctuations related to the purchase and sale of commodities in the course of normal operations; and
- foreign exchange fluctuations on foreign currency denominated purchases and sales.

The Company also enters into physical contracts for energy commodities. Collectively, these contracts are considered "derivatives". The Company accounts for derivatives under one of the following two approaches:

1. Physical contracts that meet the NPNS exception are not recognized on the balance sheet; they are recognized in income when they settle. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exception if the criteria are no longer met.
2. Derivatives entered into by NSPI, that are documented as economic hedges, and for which the NPNS exception has not been taken, receive regulatory deferral as approved by the UARB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized when the derivatives settle. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates through the FAM.

Derivative assets and liabilities as at December 31 receiving regulatory deferral consisted of the following:

	Derivative Assets		Derivative Liabilities	
millions of Canadian dollars	**2011**	2010	**2011**	2010
Current				
Commodity swaps and forwards				
Coal purchases	**$5.4**	$23.6	**$0.1**	$1.9
Natural gas purchases and sales	**0.7**	0.8	**33.5**	20.3
Heavy fuel oil ("HFO") purchases	**-**	1.9	**-**	1.3
Foreign exchange forwards	**6.0**	2.1	**-**	1.2
Physical natural gas purchases and sales	**4.2**	4.3	**0.1**	-
Total gross current derivatives	**16.3**	32.7	**33.7**	24.7
Impact of master netting agreements with intent to settle net or simultaneously	**(0.4)**	(1.7)	**(0.4)**	(1.7)
Total current derivatives	**15.9**	31.0	**33.3**	23.0
Long-term				
Commodity swaps and forwards				
Coal purchases	**6.7**	18.5	**-**	-
Natural gas purchases and sales	**-**	0.1	**5.1**	1.8
Foreign exchange forwards	**18.2**	2.2	**7.9**	9.4
Physical natural gas purchases and sales	**3.7**	8.1	**-**	-
Total gross long-term derivatives	**28.6**	28.9	**13.0**	11.2
Total long-term derivatives	**28.6**	28.9	**13.0**	11.2
Total derivatives	**$44.5**	$59.9	**$46.3**	$34.2

Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Regulatory Deferral

As previously noted, NSPI received approval from the UARB for regulatory deferral of gains and losses on certain derivatives documented as economic hedges that do not qualify for hedge accounting, including certain physical contracts that do not qualify for the NPNS exception. For the years ended December 31, the Company has recorded the following realized and unrealized gains (losses) with respect to derivatives receiving regulatory deferral:

	Regulatory Assets		**Regulatory Liabilities**	
millions of Canadian dollars	**2011**	2010	**2011**	2010
Current				
Commodity swaps and forwards				
Coal purchases	**$(1.0)**	$(20.2)	**$17.3**	$(15.9)
Natural gas purchases and sales	**13.7**	3.5	**(0.4)**	0.1
HFO purchases	**(1.3)**	(1.2)	**1.9**	8.0
Foreign exchange forwards	**(1.6)**	(20.0)	**(3.9)**	9.0
Physical natural gas purchases and sales	**0.1**	(3.9)	**0.1**	(3.9)
Long-term				
Commodity swaps and forwards				
Coal purchases	**-**	(15.3)	**11.8**	(9.0)
Natural gas purchases and sales	**3.3**	(0.2)	**0.1**	(0.1)
HFO purchases	**-**	(1.3)	**-**	2.0
Foreign exchange forwards	**(1.5)**	6.7	**(16.0)**	18.1
Physical natural gas purchases and sales	**-**	-	**4.4**	(3.9)

Regulatory Impact Recognized in Net Income

For the years ended December 31, the Company recognized the following (losses) gains related to derivatives receiving regulatory deferral:

millions of Canadian dollars	**2011**	2010
Other expenses, net	**-**	$1.5
Fuel for generation and purchased power	**$(21.3)**	(66.8)
Net losses	**$(21.3)**	$(65.3)

Commodity Swaps and Forwards

As at December 31, 2011, the Company had the following notional volumes of outstanding commodity swaps and forward contracts designated for regulatory approval that are expected to settle as outlined below:

	2012	2013	2014
millions	Purchases	Purchases	Purchases
Coal (metric tonnes)	0.5	0.3	0.1
Natural gas (Mmbtu)	20.1	7.6	-

Foreign Exchange Swaps and Forwards

As at December 31, 2011, the Company had the following notional volumes of foreign exchange swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

	2012	2013	2014	2015	2016
Fuel purchases exposure (millions of US dollars)	$256.0	$212.0	$210.0	$210.0	$120.0
Weighted average rate	0.9912	1.0251	1.0106	1.0090	0.9814
% of USD requirements	81.3%	67.3%	66.7%	66.7%	38.1%

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit assessments are conducted on all new customers and deposits are requested on any high risk accounts. The Company is also exposed to credit risk with counterparties to its derivatives. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation.

The Company assesses the potential for credit losses on a regular basis, and where appropriate, maintains provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

As at December 31, 2011, the maximum exposure the Company has to credit risk is $241.2 million (2010 - $240.0 million) which includes accounts receivable net of collateral/deposits and assets related to derivatives.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, foreign exchange and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The Company also obtains cash deposits from electric customers. The total cash deposits/collateral and letters of credit on hand as at December 31, 2011 was $11.9 million (2010 - $12.4 million) which mitigates the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements ("ISDA"), North American Energy Standards Board agreements ("NAESB") and, or Edison Electric Institute agreements. The Company believes that entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at December 31, 2011, the Company had $47.1 million (2010 - $29.6 million) in financial assets, considered to be past due, which have been outstanding for an average 76 days. The fair value of these financial assets is $39.8 million (2010 - $27.3 million), the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric revenue.

Concentration risk

The Company’s concentrations of risk as at December 31 consisted of the following:

	2011		2010	
	millions of Canadian dollars	**% of total exposure**	millions of Canadian dollars	% of total exposure
Receivables, net				
Residential	**$111.3**	**44%**	$96.3	38%
Commercial	**53.8**	**21%**	48.6	19%
Industrial	**28.8**	**11%**	32.3	13%
Other	**14.7**	**6%**	15.3	6%
	208.6	**82%**	192.5	76%
Derivative instruments (current and long-term)				
Credit rating of A- or above	**37.6**	**15%**	47.5	19%
Credit rating of BBB- to BBB+	**6.9**	**3%**	9.1	4%
Not rated	**-**	**-**	3.3	1%
	44.5	**18%**	59.9	24%
	$253.1	**100%**	$252.4	100%

Cash Collateral

The Company’s cash collateral positions as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Cash collateral provided to others	**$0.7**	$2.5

Collateral is posted in the normal course of business based on the Company’s creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company’s derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt to fall below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at December 31, 2011, the total fair value of these derivatives was a net liability position, is $46.3 million (2010 – $34.2 million). If the credit ratings of the Company were reduced below investment grade the full value of the net liability position could be required to be posted as collateral for these derivatives.

16. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exception (see note 15), and uses a market approach to do so.

The three levels of the fair value hierarchy are defined as follows:

Level 1 Valuations - Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets (“quoted prices”) for identical assets and liabilities.
Level 2 Valuations - Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 Valuations - Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally-developed inputs. NSPI’s primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.

- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

The following tables set out the classification of the methodology used by the Company to fair value its derivatives as at December 31:

				2011
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**$12.1**	**-**	**$12.1**
Natural gas purchases and sales	**$(0.4)**	**0.7**	**-**	**0.3**
Foreign exchange forwards	**-**	**24.2**	**-**	**24.2**
Physical natural gas purchases and sales	**-**	**-**	**7.9**	**7.9**
Total assets	**(0.4)**	**37.0**	**7.9**	**44.5**
Liabilities				
Regulatory deferral				
Commodity swaps and forwards				
Natural gas purchases and sales	**38.3**	**-**	**-**	**38.3**
Foreign exchange forwards	**-**	**7.9**	**-**	**7.9**
Physical natural gas purchases and sales	**-**	**-**	**0.1**	**0.1**
Total liabilities	**38.3**	**7.9**	**0.1**	**46.3**
Net (liabilities) assets	**$(38.7)**	**$29.1**	**$7.8**	**$(1.8)**

				2010
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases (1)	-	$41.2	-	$41.2
Natural gas purchases and sales (2)	$0.1	-	-	0.1
HFO purchases	-	1.9	-	1.9
Foreign exchange forwards	-	4.3	-	4.3
Physical natural gas purchases and sales	-	-	$12.4	12.4
Total assets	0.1	47.4	12.4	59.9
Liabilities				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases (1)	-	1.0	-	1.0
Natural gas purchases and sales (2)	21.3	-	-	21.3
HFO purchases	-	1.3	-	1.3
Foreign exchange forwards	-	10.6	-	10.6
Total liabilities	21.3	12.9	-	34.2
Net (liabilities) assets	$(21.2)	$34.5	$12.4	$25.7

(1) Balance was reclassified to Level 2 from Level 1
(2) Balance was reclassified to Level 1 from Level 3

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2011 was as follows:

millions of Canadian dollars	Physical natural gas purchases and sales
Balance, January 1	$12.4
Reduction of benefit included in fuel for generation and purchased power	(4.2)
Unrealized losses included in regulatory assets or liabilities	(0.3)
Balance, December 31	$7.9

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2011 was as follows:

millions of Canadian dollars	Physical natural gas purchases and sales
Balance, January 1	-
Unrealized losses included in regulatory assets or liabilities	$0.1
Balance, December 31	$0.1

The financial assets and liabilities included on the balance sheets that are not measured at fair value as at December 31 consisted of the following:

	2011		2010	
millions of Canadian dollars	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-term debt (including current portion)	**$1,961.0**	**$2,520.5**	$1,949.2	$2,293.5

The fair values of long-term debt instruments are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturity, without considering the effect of third party credit enhancements.

All other financial assets and liabilities such as cash, receivables, short-term debt and accounts payable are carried at cost. The carrying value approximates fair value due to the short-term nature of these financial instruments.

17. EMPLOYEE BENEFIT PLANS

NSPI maintains contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees; and plans providing non-pension benefits for its retirees.

Defined Benefit Plans

The Company maintains contributory defined benefit pension plans which cover the majority of the employees. The pension benefits are determined based on the years of service and average salary at the time the employee terminates employment. The plan provides annual post-retirement indexing equal to the change in the Consumer Price Index up to a maximum increase of 6% per year. The measurement date for the defined benefit pension plan is December 31.

Other retirement benefit plans ("Non-pension benefit plans") include the unfunded long service award (which is impacted by expected future salary levels) and contributory health care plan. The unfunded long service award was closed to new entrants effective August 1, 2007.

Benefit Obligation and Plan Assets

The changes in Benefit Obligation and Plan Assets, and the Funded Status for all plans for the years ended December 31 were as follows:

	2011		2010	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Change in Projected Benefit Obligation and Accumulated Post-retirement Benefit Obligation				
Balance, January 1	**$931.5**	**$39.8**	$785.2	$36.3
Service cost	**12.6**	**1.6**	9.0	1.4
Plan participant contributions	**6.0**	**-**	5.5	-
Interest cost	**50.3**	**2.1**	50.0	2.3
Plan amendments	**-**	**-**	(1.0)	-
Benefits paid	**(44.0)**	**(3.8)**	(39.5)	(4.3)
Actuarial losses	**71.3**	**0.6**	122.3	4.1
Balance, December 31	**$1,027.7**	**$40.3**	$931.5	$39.8

	2011		2010	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Reconciliation of Plan assets				
Balance, January 1	**$648.4**	**-**	$592.1	-
Employer contributions	**41.3**	**3.8**	34.6	4.3
Plan participant contributions	**6.0**	**-**	5.5	-
Benefits paid	**(44.0)**	**(3.8)**	(39.5)	(4.3)
Actual return on assets, net of expenses	**(12.0)**	**-**	55.7	-
Balance, December 31	**639.7**	**-**	648.4	-
Funded Status, end of year	**$(388.0)**	**$(40.3)**	$(283.1)	$(39.8)

As at December 31, the aggregate financial position for all pension plans where the Projected Benefit Obligation (“PBO”) or, for post-retirement benefit plans, the Accumulated Post-retirement Benefit Obligation (“APBO”), exceeds the plan assets was as follows:

Plans with PBO/APBO in excess of Plan assets	2011		2010	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
PBO/APBO	**$1,027.7**	**$40.3**	$931.5	$39.8
Fair Value of Plan Assets	**639.7**	**-**	648.4	-
Funded Status	**$(388.0)**	**$(40.3)**	$(283.1)	$(39.8)

The Accumulated Benefit Obligation (“ABO”) for the defined benefit pension plans was $957.2 as at December 31, 2011 (2010 – $882.2 million). As at December 31, the aggregate financial position for all plans with an ABO in excess of the Plan assets was as follows:

Pension Plans with ABO in excess of Plan assets	**2011**	2010
millions of Canadian dollars	**Defined benefit pension plans**	Defined benefit pension plans
ABO	**$957.2**	$882.2
Fair Value of Plan Assets	**639.7**	648.4
Funded Status	**$(317.5)**	$(233.8)

Balance Sheet

The amounts recognized in the Balance Sheets as at December 31 consisted of the following:

	2011		2010	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Current liabilities	**$(4.2)**	**$(4.1)**	$(3.7)	$(4.5)
Long-term liabilities	**(383.8)**	**(36.2)**	(279.4)	(35.3)
AOCL	**473.1**	**3.6**	362.2	3.5
Net amount recognized at end of year	**$85.1**	**$(36.7)**	$79.1	$(36.3)

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCL.

The following tables provide details on the change in AOCL during fiscal 2011 relating to these items; and the composition of the year-end balance:

Accumulated Other Comprehensive Loss millions of Canadian dollars	Actuarial losses (gains)	Past service (gains) costs
Defined Benefit Pension Plans		
Balance January 1	$363.5	$(1.3)
Amortized in current period	(22.6)	0.1
Current year addition to AOCL	133.4	-
Balance December 31	474.3	(1.2)

Accumulated Other Comprehensive Loss millions of Canadian dollars	Actuarial losses (gains)	Past service (gains) costs
Non-pension benefits plans		
Balance January 1	$2.1	$1.4
Amortized in current period	(0.3)	(0.2)
Current year addition to AOCL	0.6	-
Balance December 31	$2.4	$1.2

Accumulated Other Comprehensive Loss		**2011**		2010
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Actuarial losses	**$474.3**	**$2.4**	$363.5	$2.1
Past service (gains) costs	**(1.2)**	**1.2**	(1.3)	1.4
Net amount in AOCL	**$473.1**	**$3.6**	$362.2	$3.5

The amounts in the foregoing table were not recognized in NSPI's net periodic benefit cost as at December 31.

Benefit Cost Components

		2011		2010
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Service cost	**$12.6**	**$1.6**	$9.0	$1.4
Interest cost	**50.3**	**2.1**	50.0	2.3
Expected return on plan assets	**(50.1)**	**-**	(49.5)	-
Current year amortization of:				
Actuarial losses (gains)	**22.6**	**0.3**	9.5	(0.2)
Past service (gains) costs	**(0.1)**	**0.2**	-	0.2
Total	**$35.3**	**$4.2**	$19.0	$3.7

The expected return on plan assets is determined based on the market-related value of plan assets of $714.8 million as at January 1, 2011 (2010 – $684.6 million), adjusted for interest on certain cash flows during the year. The market related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight line basis into the market related value of assets over a five-year period.

Pension Plan Assets

NSPI's defined benefit pension plan employs a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return given the Company's goal of preserving capital within an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation pension assets are overseen by external investment managers per the pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of Canadian and global equities, domestic bonds, and short-term investments. NSPI reviews investment manager performance on a regular basis and adjusts the plans' asset mixes as needed in accordance with the pension plan's investment policy.
NSPI's target asset allocation is as follows:

Asset Class	Target Range at Market		
Short term securities	0%	to	5%
Fixed income	25%	to	40%
Equities:			
Canadian	23%	to	33%
Non-Canadian (World)	32%	to	42%

The investment of the pension assets, including the performance of investment managers, is overseen by the NSPI Pension Committee. The fair values of investments as at December 31, 2011, by asset category, are as follows:

millions of Canadian dollars	Level 1	%
Cash and cash equivalents	$15.8	2.5%
Equity Securities:		
Canadian equity	161.8	25.3%
International equity	225.9	35.3%
Fixed income securities:		
Canadian government	141.3	22.1%
Corporate debt	94.9	14.8%
Total	$639.7	100.0%

The fair values of investments as at December 31, 2010, by asset category, are as follows:

millions of Canadian dollars	Level 1	%
Cash and cash equivalents	$8.2	1.3%
Equity Securities:		
Canadian equity	192.4	29.7%
International equity	230.7	35.6%
Fixed income securities:		
Canadian government	122.1	18.8%
Corporate debt	95.0	14.6%
Total	$648.4	100%

Refer to Note 1(U), "*Summary of Significant Accounting Policies – Fair Value Measurement*," for more information on the fair value hierarchy and inputs used to measure fair value. All investments were deemed Level 1 for the years ended December 31, 2011 and 2010.

Investments in Emera Incorporated or NSPI

As at December 31, 2011 and 2010, the pension funds do not hold any material investments in Emera Incorporated ("Emera") or NSPI securities. However, as a significant portion of assets for the benefit plan are held in pooled funds, there may be indirect investments in these securities.

Other post-retirement benefit plan assets

There are no assets set aside to pay for the post-retirement benefit plans. As is common in Canada, post-retirement health benefits are paid from NSPI's general accounts on a pay as you go basis.

Cash Flows

The following table shows the expected cash flows for defined benefit pension and other post-retirement benefit plans:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefits plans
Expected Employer contributions:		
2012	$66.2	$4.1
Expected Benefit Payments:		
2012	47.7	4.1
2013	50.8	4.7
2014	54.1	5.0
2015	57.7	5.2
2016	61.6	5.5
2017 - 2021	374.9	32.8

Assumptions

The following table shows the assumptions that have been used in accounting for defined benefit pension and other post-retirement benefit plans:

	2011		2010	
(weighted average assumptions)	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Benefit obligation – December 31:				
Discount rate	**5.00%**	**5.00%**	5.50%	5.50%
Rate of compensation increase	**3.5%**	**3.5%**	3.75%	3.75%
Health care trend - initial (next year)	**-**	**3.75%**	-	4.00%
- ultimate	**-**	**3.75%**	-	4.00%
- year ultimate reached	**-**	**2011**	-	2011
Benefit cost for year ending December 31:				
Discount rate	**5.50%**	**5.50%**	6.50%	6.50%
Expected long-term return on plan assets	**7.00%**	**-**	7.25%	-
Rate of compensation increase	**3.75%**	**3.75%**	3.75%	3.75%
Health care trend - initial (current year)	**-**	**4.00%**	-	5.00%
- ultimate	**-**	**4.00%**	-	4.00%
- year ultimate reached	**-**	**-**	-	2011

The expected long-term rate of return on plan assets is based on historical and projected real rates of return for the plan's current asset allocation, and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined. The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

Sensitivity Analysis for Non-Pension Benefits Plans

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2011:

millions of Canadian dollars	Increase	Decrease
Service cost and interest cost	$0.2	$(0.2)
Accumulated post-retirement benefit obligation, December 31	1.6	(1.5)

Amounts to be Amortized in the Next Fiscal Year

The following table shows the amount from the AOCL which are expected to be recognized as part of the net periodic benefit cost in fiscal 2012:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefits plans
Actuarial (losses)	$(29.6)	$(0.3)
Past service gains (costs)	0.2	(0.2)
Total	$(29.4)	$(0.5)

Defined Contribution Plan

The Company also provides a defined contribution pension plan for certain employees. The Company's contribution for 2011 was $1.6 million (2010 – $1.3 million).

18. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2011, commitments (excluding pension and other post-retirement benefits, long-term debt, and ARO) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2012	2013	2014	2015	2016	Thereafter	Total
Purchased power (1)	$68.4	$81.3	$85.2	$85.2	$85.2	$1,128.6	$1,533.9
Coal, biomass, oil and natural gas supply	203.5	120.3	64.0	21.9	22.4	599.9	1,032.0
Transportation (2)	48.8	11.2	10.4	1.2	-	-	71.6
Long-term service agreements (3)	9.7	9.8	4.3	4.4	0.5	-	28.7
Capital projects	30.3	1.3	-	-	-	-	31.6
Leases (4)	1.0	0.9	0.8	0.8	0.5	6.3	10.3
Other	0.4	-	-	-	-	-	0.4
Total	$362.1	$224.8	$164.7	$113.5	$108.6	$1,734.8	$2,708.5

(1) Purchased power: annual requirement to purchase 100 percent of electricity production from independent power producers over varying contract lengths up to 25 years.
(2) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on the Maritimes & Northeast Pipeline ("M&NP").
(3) Long-term service agreements: outsourced management of the Company's computer and communication infrastructure and vegetation management.
(4) Leases: operating lease agreements for office space, land leases and rail cars.

B. Legal Proceedings

A number of individuals who live in proximity to the Company's Trenton generating station have filed a statement of claim for an unspecified amount against NSPI in respect of emissions from the operation of the plant for the period from 2001 forward. The plaintiffs claim unspecified damages as a result of interference with enjoyment of, or damage to, their property; and adverse health effects they allege were caused by such emissions. The Company has filed a defense to the claim. The outcome of this litigation, and therefore an estimate of any contingent loss, is not determinable.

In addition, the Company may, from time to time, be involved in legal proceedings, claims and litigations that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. Environment

NSPI's activities are subject to a broad range of federal, provincial, regional and local laws and environmental regulations, designed to protect, restore, and enhance the quality of the environment including air, water and solid waste. NSPI's environmental capital expenditures, excluding AFUDC, based upon present environmental laws and regulations were $65.9 million during 2011 and are estimated to be $439.0 million from 2012 through 2015. Amounts that have been committed are included in "Capital projects" in the commitments included in note 18A. The estimated expenditures do not include costs related to possible changes in the environmental laws or regulations and enforcement policies may be enacted in response to issues such as climate change and other pollutant emissions.

NSPI is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters primarily through its utility operations. In addition to imposing continuing compliance obligations, there are laws, regulations and permits authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is material to the Company. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on the Company.

Conformance with legislative and Company requirements are verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the 2011 and 2010 audits.

Climate Change and Air Emissions

Greenhouse Gas Emissions

NSPI has stabilized, and in recent years, reduced greenhouse gas emissions. This has been achieved by energy efficiency and conservation programs, increased use of natural gas and the addition of new renewable energy sources to the generation portfolio.

Greenhouse gas emissions from NSPI facilities have been capped beginning in 2010 through to 2020. The regulations allow for multi-year compliance periods recognizing the variability in electricity supply sources and demand. Over the decade, the caps will be achieved by a combination of additional renewable generation, import of non-emitting energy, and energy efficiency and conservation.

In 2011, Environment Canada announced proposed regulations for a new national carbon dioxide framework for the electricity sector in Canada. These proposed regulations would apply to new coal-fired electricity generation units; and existing coal-fired electricity generation units that have reached the end of their deemed economic life of forty-five years after commissioning. These proposed regulations will be effective July 1, 2015. Nova Scotia's existing greenhouse gas regulations require reductions in NSPI's emissions similar to those reflected in the federal framework. NSPI is engaged with federal and provincial agencies in reviewing the implications of this federal framework and its alignment with its current operating plans under existing Nova Scotia regulations.

Renewable Energy

The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI’s generation mix. The target date for 5 percent of electricity to be supplied from post-2001 sources of renewable energy, owned by independent power producers, was extended to 2011 from 2010. The target for 2013, which requires an additional 5 percent of renewable energy, is unchanged.

On May 19, 2011 the Nova Scotia Government approved The Electricity Act (Amended) to facilitate the eligibility of energy from the Lower Churchill Project in Labrador as a resource for meeting Nova Scotia's renewable electricity targets. The amendment requires regulations to be developed that increase the percentage of renewable energy in the generation mix from the planned 25 percent in 2015, to 40 percent by 2020.

Mercury, Nitrogen Oxide and Sulphur Dioxide Emissions

NSPI completed a capital program to add sorbent injection to each of the seven pulverized fuel coal units in 2010 at a cost of $17.3 million. This was put in place to address planned reductions in mercury emissions limits, which are set out in the following table:

Year	Mercury Emissions Limit (kg)
2009	168
2010	110
2011 - 2012	100
2013	85
2014 - 2019	65
2020	35

Any mercury emission above 65 kg, between 2010 and 2013, must be offset by lower emissions in the 2014 to 2020 period.
NSPI completed its capital program of retrofitting low nitrogen oxide combustion firing systems on six of its seven pulverized fuel coal units in early 2009 at a cost of $23.3 million. NSPI now meets the nitrogen oxide emission cap of 21,365 tonnes per year established by the Nova Scotia Government effective

2010. These investments, combined with the purchasing of low sulfur coal, allows NSPI to meet the provincial air quality regulations.

NSPI will meet ever-reducing sulphur dioxide emission cap requirements through the use of a blend of net lower sulphur content solid fuel.

Compared to historical levels, NSPI will have reduced mercury emissions by 60 percent effective 2014, nitrogen oxide by 40 percent effective 2009 and sulphur dioxide by 50 percent effective 2010.

Poly Chlorinated Bi-Phenol Transformers

In response to the Canadian Environmental Protection Act 1999, 2008 Poly Chlorinated Bi-Phenol ("PCB") Regulations to phase out electrical equipment and liquids containing PCBs, NSPI has implemented a program to eliminate transformers and other electrical equipment on its system that do not meet the 2008 PCB Regulations Standard by 2014. In addition, there is a project to phase out the use of pole mount transformers before 2025 including a capital program to destroy all confirmed PCB contaminated pole mount transformers taken out of service through attrition. The combined total cost of these projects is estimated to be $36.5 million and, as at December 31, 2011 approximately $7.8 million (2010 - $5.4 million) has been spent to date. NSPI has recognized an ARO of $20.6 million as at December 31, 2011 (2010 - $13.9 million) associated with the PCB phase-out program.

D. Principal Risks and Uncertainties

In this section, NSPI describes some of the principal risks management believes could materially affect NSPI's business, revenues, operating income, net income, net assets or liquidity or capital resources. The nature of risk is such that no list can be comprehensive, and other risks may arise or risks not currently considered material may become material in the future.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. NSPI has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach.

Regulatory Risk

The Company is regulated by the UARB and is subject to risk in the recovery of costs and investments in a timely manner. The Company manages this regulatory risk through transparent regulatory disclosure, ongoing stakeholder consultation and multi-party engagement on aspects such as utility operations, rate filings and capital plans.

Changes in Environmental Legislation

The Company is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters primarily related to its utility operations. Changes to climate change and air emissions standards could adversely affect utility operations.

NSPI is committed to operating in a manner that is respectful and protective of the environment, and in full compliance with legal requirements and Company policy. NSPI has implemented this policy through development and application of environmental management systems.

Commodity Prices and Foreign Exchange Rate Fluctuations in Fuel Prices

Commodity price fluctuations related to the purchase of fuel for generation and purchased power and foreign exchange fluctuations on foreign currency denominated purchases of fuel affect NSPI's fuel costs. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts and utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. The strategy is designed to reduce the effects from market volatility through agreements with staggered expiration dates, volume options and varied pricing mechanisms. The adoption and implementation of the FAM, effective January 1, 2009, has further helped NSPI manage this risk.

Commercial Relationships

For the year ended December 31, 2011, NSPI's five largest customers contributed approximately 13.3 percent (2010 – 14.7 percent) of electric revenues. The loss of a large customer could have a material effect on NSPI's operating revenues. NSPI works to mitigate this risk through the regulatory process.

NSPI's largest customer was granted creditor protection under the Companies Creditors' Arrangement Act ("CCAA"), and suspended operations in September 2011. This customer contributed approximately 6.0 percent (2010 – 7.9 percent) of NSPI's electric revenues for the year ended December 31, 2011. NSPI is working to recover an outstanding balance of $11.6 million through the CCAA claims process, including a claim for set-off against amounts owing from NSPI to the customer that exceeds the amount receivable. The 2012 General Rate Decision, approved by the UARB, provides for any unrecovered non-fuel electric charges in 2012 related to this customer to be deferred and recovered beginning in 2013.

Labour Risk

Certain NSPI employees are subject to a collective labour agreement which will expire on March 31, 2012. Approximately 52 percent of NSPI's full-time and term employees are represented by a local union affiliated with the International Brotherhood of Electrical Workers. NSPI seeks to manage this risk through ongoing discussions with the union.

Weather Risk

Shifts in weather patterns affect electric sales volumes and associated revenues with increased volatility in the winter months attributed to heating loads. Extreme weather events generally result in increased operating costs associated with restoring power to customers. NSPI responds to significant weather event related outages according to its Emergency Services Restoration Plan.

Interest Rate Risk

The Company utilizes a combination of fixed and variable rate debt financing for operations and capital expenditures resulting in an exposure to interest rate risk. The Company seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt. The Company has no interest rate hedging contracts outstanding as at December 31, 2011.

E. Guarantees and Letters of Credit

NSPI had the following guarantees and letters of credits as at December 31, 2011:

- NSPI has provided a limited guarantee for the indebtedness of RESL. The guarantee is up to a maximum of $23.5 million. As at December 31, 2011, RESL's indebtedness under the loan agreement was $21.9 million. NSPI holds a security interest in the present and future assets of RESL. For further information refer to Note 1V.

- A financial institution has issued a standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2012 and is renewed annually. The amount committed as at December 31, 2011 was $22.5 million.

No liability has been recognized in the balance sheets related to any potential obligation under these guarantees and letters of credits.

19. REDEEMABLE PREFERRED STOCK

Redeemable preferred stock is considered mezzanine equity and is presented outside of equity because the preferred stock is exchangeable at the option of the holder into Emera common stock.

Authorized:

Unlimited number of First Preferred shares, issuable in series.
Unlimited number of Second Preferred shares, issuable in series.

		2011		2010
Issued and outstanding:	**Millions of shares**	**Millions of Canadian dollars**	Millions of shares	Millions of Canadian dollars
Redeemable Preferred Stock	**5.4**	**$135.0**	5.4	$135.0
Issue costs		**(2.8)**		(2.8)
		$132.2		$132.2

Series D First Preferred Stock:

On and after October 15, 2015, Series D First Preferred Stock is redeemable by NSPI, in whole at any time or in part from time to time at $25 per share plus accrued and unpaid dividends. NSPI also has the option, commencing October 15, 2015, to exchange the Series D First Preferred Stock into Emera common stock determined by dividing $25 by the greater of $2 and the market price of the Emera common stock.

Commencing on and after January 15, 2016, with prior notice and prior to any dividend payment date, each Series D First Preferred Stock will be exchangeable at the option of the holder into fully paid and freely tradable Emera common stock determined by dividing $25 by the greater of $2 and the market price of the Emera common stock, subject to the right of NSPI to redeem such stock for cash or to cause the holders of such stock to sell on the exchange date all or any part of such stock to substitute purchasers found by NSPI. NSPI will pay all accrued and unpaid dividends to the exchange date.

Each Series D First Preferred Stock is entitled to a $1.475 per share per annum fixed cumulative preferential dividend, as and when declared by the Board of Directors, accruing from the date of issue and payable quarterly on the fifteenth day of January, April, July and October of each year.

The First Preferred Shares of each series rank on a parity with the First preferred Shares of every other series and are entitled to a preference over the Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares will be entitled to attend any meeting of shareholders of the Company and to vote at any such meeting.

20. STOCK-BASED COMPENSATION

EMPLOYEE COMMON STOCK PURCHASE PLAN

Employees may participate in Emera's Employee Common Share Purchase Plan to which employees make cash contributions for the purpose of purchasing common shares of NSPI's parent company, Emera. The Company also contributes to the plan a percentage of the employees' contributions. The plan allows the reinvestment of dividends. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 2.0 million common shares.

The Company uses the fair value based method to measure the compensation expense related to the employee purchase plan and recognizes the expense over the vesting period on a straight-line basis.

Emera issued approximately 17,853 shares for the year ending December 31, 2011 (2010 – 19,677 shares) to employees of NSPI under the employee common share purchase plan for compensation cost of $0.6 million (2010 – $0.5 million). The compensation cost related to Emera shares issued to NSPI employees is recorded as “Operating, maintenance and general expense”.

STOCK-BASED COMPENSATION PLANS

The Company has deferred share unit (“DSU”) and performance share unit (“PSU”) plans. The DSU and PSU liabilities are marked-to-market at the end of each period based on the common share price at the end of the period.

Deferred Share Unit Plan

Under the Directors’ DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation. Directors’ fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera’s common shares referred to as the Dividend Reinvestment Plan (“DRIP”), the Director’s DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns, or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50% of the value of their actual annual incentive award (25% in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera’s common shares, each participant’s DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares, referred to as DRIP. Following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant’s account is calculated by multiplying the number of DSUs in the participant’s account by the average of Emera’s stock closing price for the fifty trading days prior to a given calculation date. Payments are usually made in cash. At the sole discretion of the Management Resources and Compensation Committee (“MRCC”), payments may be made in the form of actual shares.

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or to achieve certain corporate objectives.

A summary of the activity related to employee and director DSU’s for the year ended December 31, 2011 is presented in the following table:

	Employee DSU	Weighted Average Grant Date Fair Value	Director DSU	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2010	63,922	$21.95	47,381	$22.35
Granted	10,588	31.16	12,335	32.29
Transferred	(7,097)	22.60	-	-
Outstanding as at December 31, 2011	67,413	$23.33	59,716	$24.40

Compensation cost recognized for employee and director DSU for the year ended December 31, 2011 was $0.4 million (2010 – $0.8 million). Tax benefits related to compensation cost for share units realized for the year ended December 31, 2011 were $0.1 million (2010 – $0.2 million).

Performance Share Unit Plan

Under the PSU plan, Executive and senior employees are eligible for long-term incentives payable through the PSU plan. PSUs are granted annually for three-year overlapping performance cycles. PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Dividend equivalents are awarded and are used to purchase additional PSUs, also referred to as DRIP. The PSU value varies according to the Emera common share market price and corporate performance.

PSUs vest at the end of the three-year cycle and will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and will be pro-rated in the case of retirement, disability or death.

A summary of the activity related to employee PSU's for the year ended December 31, 2011 is presented in the following table:

	Employee PSU	Weighted-Average Grant Date Fair Value
Outstanding as at December 31, 2010	145,922	$25.95
Granted including DRIP	45,718	31.18
Exercised	(54,469)	23.13
Transferred	(31,725)	28.50
Outstanding as at December 31, 2011	105,446	$28.90

Compensation cost recognized for employee PSU for the year ended December 31, 2011 was $1.3 million (2010 – $2.3 million). Tax benefits related to compensation cost for share units realized for the year ended December 31, 2011 were $0.4 million (2010 – $0.7 million).

Non-vested Stock-Based Compensation Plans

For the year ended December 31, 2011, a summary of activity from the different plans is presented in the following table:

		DSU Plan		**PSU Plan**
	Number of share units	Weighted Average Grant Date Fair Value	Number of share units	Weighted Average Grant Date Fair Value
Non-vested shares as at December 31, 2010	5,044	$22.39	91,453	$27.62
Granted including DRIP	130	31.09	45,718	31.18
Vested	(1,947)	21.51	(39,138)	23.79
Transferred	(1,150)	20.82	(31,725)	28.50
Non-vested shares as at December 31, 2011	2,077	$24.63	66,308	$31.92

The total fair value of shares vested for all the plans was $5.4 million for the year ended December 31, 2011 (2010 - $5.0 million). The weighted-average grant date fair value of shares, granted for all the plans, for the year ended December 31, 2011 was $26.13 (2010 - $24.29).

Fully Vested Stock-Based Compensation Plans

	Share Unit Plan	
	DSU Plan	**PSU Plan**
Outstanding		
Number of share units	125,053	39,138
Aggregate fair value of share units	$4,131,740	$1,293,119

21. RELATED PARTY TRANSACTIONS

The Company enters into transactions with related parties in the normal course of operations. All related party transactions with NSPI are governed by an affiliate Code of Conduct that is approved by the UARB.

NSPI, Emera Energy Services ("EES"), Bangor Hydro Electric Company ("Bangor Hydro"), Emera Utility Services ("EUS") and Emera Newfoundland and Labrador ("ENL") are wholly owned subsidiaries of Emera. Emera owns a 12.9 percent interest in M&NP.

Related party transactions with NSPI for the years ended December 31 are summarized in the following table:

millions of Canadian dollars

	Nature of Service	Presentation	2011	2010
Sales:				
Emera	Corporate support and other services	Operating, maintenance and general ("OM&G")	**$3.3**	$3.0
Emera	Contract revenues	Operating revenues	**-**	1.0
EES	Corporate support and other services	OM&G	**1.2**	1.2
Bangor Hydro	Corporate support and other services	OM&G	**0.9**	0.9
Other	Corporate support and other services	OM&G	**2.0**	1.2
Purchases:				
EES	Net purchase of electricity	Fuel for generation and purchased power – affiliates	**-**	6.2
EES	Net purchase of natural gas	Fuel for generation and purchased power – affiliates	**1.1**	0.9
Emera	Purchase of power	Fuel for generation and purchased power – affiliates	**-**	1.0
EUS	Maintenance services	OM&G	**5.6**	2.2
EUS	Purchase of inventory	Inventory	**0.5**	1.1
EUS	Construction services	Property, plant and equipment	**16.6**	43.5

Beginning in Q2 2011, NSPI has recorded the impact of two agreements with Emera on a net basis in the statements of income. Under the agreements, NSPI purchased power from Emera and received contract revenues from Emera of $9.8 million (2010 - $1.0 million) for the year ended December 31, 2011.

In the ordinary course of business, the Company purchased $14.3 million (2010 - $18.0 million) in natural gas transportation capacity from M&NP for the year ended December 31, 2011. The amount is recognized in "Fuel for generation and purchased power" and is measured at the exchange amount. As at December 31, 2011, the amount payable to M&NP is $0.8 million (2010 – $1.0 million) and is under normal interest and credit terms.

For the years ended December 31, 2011 and 2010, the Company issued 5.0 million common shares to Emera and an affiliate under common control of Emera for total consideration of $50.0 million.

On May 28, 2010, NSPI purchased $30.1 million in wind generation assets under development related to the Digby Wind Project from a subsidiary of Emera. This transaction was measured at the carrying amount of the assets transferred. As at December 31, 2011 and 2010, there were no amounts due.

As at December 31, amounts due (to) from related parties are summarized in the following table:

millions of Canadian dollars	**2011**	2010
Due from related parties:		
Emera	**$0.4**	-
ENL	**0.1**	-
EES	**-**	$0.7
	0.5	0.7
Due to related parties:		
EUS	**(1.7)**	(5.5)
EES	**(0.1)**	-
Emera	**-**	(1.4)
	(1.8)	(6.9)
Net due to related parties	**$(1.3)**	$(6.2)

22. QUARTERLY DATA (UNAUDITED)

For the quarter ended millions of Canadian dollars	**Q4 2011**	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Operating revenues	**$289.2**	$276.0	299.0	$368.8	$303.2	$272.2	$273.2	$342.8
Net Income of NSPI	**24.1**	23.0	18.7	65.6	21.8	20.6	17.5	67.2
Net income attributable to common shareholders	**22.2**	21.0	16.7	63.6	19.9	18.6	15.5	65.2

23. USGAAP TRANSITION

ADOPTION OF USGAAP

In February 2008, the Canadian Institute of Chartered Accountants ("CICA") announced that CGAAP for publically accountable enterprises would be replaced by IFRS for fiscal years beginning on or after January 1, 2011. In Q4 2009, due primarily to the continued uncertainty around the applicability of a rate-regulated accounting standard under IFRS, management of Emera, NSPI's parent company, reviewed the option of adopting USGAAP instead of IFRS. In Q1 2010, the Company decided to transition to USGAAP as recommended by management. The adoption of USGAAP has been made on a retrospective basis with restatement of prior periods' financial statements to reflect USGAAP requirements in effect at that time.

For annual reporting purposes, the transition date to USGAAP is January 1, 2010, which is the commencement of the 2010 comparative period to the Company's 2011 financial statements.

As a result of NSPI's decision to transition to USGAAP, effective January 1, 2011, there was an amendment to the Company's regulated accounting policy for financial instruments and hedges which was approved by the UARB. The effects of this amendment were applied retrospectively, in accordance with that policy, without restatement of prior period income. The adjustments related to the amended accounting policy have been included with the adjustments as described further in this note.

Measurement, classification and disclosure differences arising out of the Company's election to adopt USGAAP are presented below. With respect to measurement and classification differences, Section I "USGAAP differences", presents quantitative reconciliations of balance sheets, income statements and statements of cash flows, previously presented in accordance with CGAAP, to the respective amounts and classifications under USGAAP, together with descriptions of the various significant measurement and classification differences arising from the adoption of USGAAP. Balance sheet reconciliations are presented as at January 1, 2010 and December 31, 2010, representing the commencement and ending dates of the comparative financial year to 2011. Income statement and statement of cash flow reconciliations are presented for the three, six and nine months ended March 31, 2010, June 30, 2010 and September 30, 2010, respectively, and for the year ended December 31, 2010, which are periods that will be presented as comparatives to 2011 financial reporting.

In addition, USGAAP requires certain disclosures of financial information, significant to the Company, that are in addition to the required disclosure under CGAAP.

Except as otherwise disclosed in this note, the change in basis of accounting from CGAAP to USGAAP did not materially impact accounting policies or disclosures. Reference should be made to the previously filed CGAAP financial statements as at and for the year ended December 31, 2010 for additional information on CGAAP accounting policies and practices.

The following table summarizes the increases (decreases) to total assets:

As at millions of Canadian dollars	January 1 2010	December 31 2010
Total assets – CGAAP	$3,465.3	$3,991.3
Note A – Offsetting	(0.9)	-
Note B – Income taxes	16.1	(128.5)
Note E – Hedging	95.9	39.1
Note I – Pension and other post-retirement benefits	(94.3)	(110.7)
Note J – Issue costs	11.6	13.7
Other	0.1	(0.2)
Total transition adjustments	28.5	(186.6)
Total assets – USGAAP	$3,493.8	$3,804.7

The following table summarizes the increases (decreases) to total liabilities:

As at millions of Canadian dollars	January 1 2010	December 31 2010
Total liabilities – CGAAP	$2,379.9	$2,779.8
Note A – Offsetting	(0.9)	-
Note B – Income taxes	17.3	(123.1)
Note E – Hedging	51.9	49.8
Note I – Pension and other post-retirement benefits	168.6	259.5
Note J – Issue costs	12.7	14.8
Note M – Redeemable preferred stock	(134.0)	(134.1)
Note N – Share based compensation	0.9	1.1
Other	-	(0.1)
Total transition adjustments	116.5	67.9
Total liabilities – USGAAP	$2,496.4	$2,847.7

The following table summarizes the increases (decreases) to net income:

For the millions of Canadian dollars	3 months ended March 31 2010 (unaudited)	6 months ended June 30 2010 (unaudited)	9 months ended September 30 2010 (unaudited)	Year ended December 31 2010
Net income attributable to common shareholders - CGAAP	$63.3	$78.2	$100.6	$121.3
Note B – Income taxes	1.2	1.4	(3.0)	(4.2)
Note I – Pension and other post-retirement benefits	0.6	1.1	1.7	2.3
Note M – Redeemable preferred stock	-	0.1	0.1	0.1
Note N – Share based compensation	-	-	(0.1)	(0.2)
Other	0.1	(0.1)	-	(0.1)
Total transition adjustments	1.9	2.5	(1.3)	(2.1)
Net income attributable to common shareholders – USGAAP	$65.2	$80.7	$99.3	$119.2

USGAAP differences

The reconciliations of the January 1, 2010 and December 31, 2010 balance sheets from CGAAP to USGAAP are as follows:

As at January 1, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Assets				
Current assets				
Cash		$0.3	-	$0.3
Receivables, net	A	271.8	$(0.9)	270.9
Inventory		165.6	-	165.6
Deferred income taxes	B	34.4	(22.3)	12.1
Derivatives in a valid hedging relationship	C	19.4	(19.4)	-
Held-for-trading derivatives	C	8.9	(8.9)	-
Derivative instruments	C	-	28.3	28.3
Regulatory assets	D, E	-	122.7	122.7
Prepaid expenses		5.7	-	5.7
Other current assets	F	-	1.5	1.5
Total current assets		506.1	101.0	607.1
Property, plant and equipment	B, G	2,365.6	153.8	2,519.4
Construction work-in-progress	G	152.8	(152.8)	-
		2,518.4	1.0	2,519.4
Other assets				
Deferred income taxes	B	-	61.4	61.4
Derivatives in a valid hedging relationship	C	29.8	(29.8)	-
Held-for-trading derivatives	C	6.2	(6.2)	-
Derivative instruments	C	-	36.0	36.0
Regulatory assets	B, D, E	-	193.0	193.0
Intangibles	H	65.7	(65.7)	-
Other	B, D, F, H, I, J	339.1	(262.2)	76.9
Total other assets		440.8	(73.5)	367.3
Total assets		$3,465.3	$28.5	$3,493.8

As at January 1, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Liabilities and Equity				
Current liabilities				
Short-term debt		$198.2	$0.1	$198.3
Current portion of long-term debt		100.7	-	100.7
Accounts payable	A, K	-	151.7	151.7
Accounts payable and accrued charges	K	213.9	(213.9)	-
Due to related parties	N	0.7	0.9	1.6
Income taxes payable	B	1.2	2.1	3.3
Dividends payable	L	1.7	(1.7)	-
Derivatives in a valid hedging relationship	C	53.0	(53.0)	-
Held-for-trading derivatives	C	12.2	(12.2)	-
Derivative instruments	C	-	65.2	65.2
Pension and post-retirement liabilities	I	-	8.3	8.3
Regulatory liabilities	B, D, E	-	45.6	45.6
Other current liabilities	B, F, K, L, M	-	65.9	65.9
Total current liabilities		581.6	59.0	640.6
Long-term liabilities				
Long-term debt	J, M	1,397.0	13.3	1,410.3
Deferred income taxes	B	52.0	(52.0)	-
Derivatives in a valid hedging relationship	C	20.0	(20.0)	-
Held-for-trading derivatives	C	1.3	(1.3)	-
Derivative instruments	C	-	21.3	21.3
Pension and post-retirement liabilities	I	-	221.2	221.2
Regulatory liabilities	B, D, E	-	87.1	87.1
Asset retirement obligations		101.5	-	101.5
Other long-term liabilities	D, F, I	91.5	(77.1)	14.4
Preferred shares	M	135.0	(135.0)	-
Total long-term liabilities		1,798.3	57.5	1,855.8
Redeemable preferred stock	M	-	132.2	132.2
Equity				
Common stock		934.7	-	934.7
Accumulated other comprehensive loss	E, I	(44.0)	(212.1)	(256.1)
Retained earnings	B, I, J, M, N	194.7	(8.1)	186.6
Total equity		1,085.4	(220.2)	865.2
Total liabilities and equity		$3,465.3	$28.5	$3,493.8

As at December 31, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Assets				
Current assets				
Cash		$0.3	-	$0.3
Receivables, net		192.5	-	192.5
Income taxes receivable	B	40.6	$(6.3)	34.3
Inventory		154.2	-	154.2
Deferred income taxes	B	4.1	(4.1)	-
Derivatives in a valid hedging relationship	C	24.7	(24.7)	-
Held-for-trading derivatives	C	6.3	(6.3)	-
Derivative instruments	C	-	31.0	31.0
Regulatory assets	D, E	-	71.8	71.8
Prepaid expenses		6.1	(0.1)	6.0
Other current assets	F	-	1.8	1.8
Total current assets		428.8	63.1	491.9
Property, plant and equipment	B, G	2,669.0	280.5	2,949.5
Construction work-in-progress	G	279.2	(279.2)	-
		2,948.2	1.3	2,949.5
Other assets				
Deferred income taxes	B	-	16.8	16.8
Derivatives in a valid hedging relationship	C	20.8	(20.8)	-
Held-for-trading derivatives	C	8.2	(8.2)	-
Derivative instruments	C	-	28.9	28.9
Regulatory assets	B, D, E	-	232.5	232.5
Intangibles	H	72.5	(72.5)	-
Other	B, D, F, H, I, J	512.8	(427.7)	85.1
Total other assets		614.3	(251.0)	363.3
Total assets		$3,991.3	$(186.6)	$3,804.7

As at December 31, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Liabilities and Equity				
Current liabilities				
Short-term debt		$48.3	-	$48.3
Current portion of long-term debt		0.1	-	0.1
Accounts payable	K	-	$157.9	157.9
Accounts payable and accrued charges	K	221.3	(221.3)	-
Due to related parties	N	5.1	1.1	6.2
Dividends payable	L	1.7	(1.7)	-
Deferred income taxes	B	-	3.4	3.4
Derivatives in a valid hedging relationship	C	2.2	(2.2)	-
Held-for-trading derivatives	C	20.8	(20.8)	-
Derivative instruments	C	-	23.0	23.0
Pension and post-retirement liabilities	I	-	8.2	8.2
Regulatory liabilities	B, D, E	-	52.4	52.4
Other current liabilities	B, F, K, L, M	-	67.2	67.2
Total current liabilities		299.5	67.2	366.7
Long-term liabilities				
Long-term debt	J, M	1,933.7	15.4	1,949.1
Deferred income taxes	B	163.1	(163.1)	-
Derivatives in a valid hedging relationship	C	9.4	(9.4)	-
Held-for-trading derivatives	C	1.8	(1.8)	-
Derivative instruments	C	-	11.2	11.2
Pension and post-retirement liabilities	I	-	314.7	314.7
Regulatory liabilities	B, D, E	-	61.7	61.7
Asset retirement obligations		138.7	-	138.7
Other long-term liabilities	D, F, I, K	98.6	(93.0)	5.6
Preferred shares	M	135.0	(135.0)	-
Total long-term liabilities		2,480.3	0.7	2,481.0
Redeemable preferred stock	M	-	132.2	132.2
Equity				
Common stock		984.7	-	984.7
Accumulated other comprehensive income (loss)	E, I	10.8	(376.5)	(365.7)
Retained earnings	B, I, J, M, N	216.0	(10.2)	205.8
Total equity		1,211.5	(386.7)	824.8
Total liabilities and equity		$3,991.3	$(186.6)	$3,804.7

The adjustments to January 1, 2010 and December 31, 2010 equity are as follows:

As at January 1, 2010 millions of Canadian dollars	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Equity
CGAAP	$934.7	$(44.0)	$194.7	$1,085.4
Note B – Income taxes	-	-	(1.2)	(1.2)
Note E – Hedging	-	44.0	-	44.0
Note I – Pension and other post-retirement benefits	-	(256.1)	(6.8)	(262.9)
Note J – Issue costs	-	-	(1.1)	(1.1)
Note M – Redeemable preferred stock	-	-	1.8	1.8
Note N – Stock-based compensation	-	-	(0.9)	(0.9)
Other			0.1	0.1
Total transition adjustments	-	(212.1)	(8.1)	(220.2)
USGAAP	$934.7	$(256.1)	$186.6	$865.2

As at December 31, 2010 millions of Canadian dollars	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Equity
CGAAP	$984.7	$10.8	$216.0	$1,211.5
Note B – Income taxes	-	-	(5.4)	(5.4)
Note E – Hedging	-	(10.7)	-	(10.7)
Note I – Pension and other post-retirement benefits	-	(365.7)	(4.5)	(370.2)
Note J – Issue costs	-	-	(1.1)	(1.1)
Note M – Redeemable preferred stock	-	-	1.9	1.9
Note N – Stock-based compensation	-	-	(1.1)	(1.1)
Other	-	(0.1)	-	(0.1)
Total transition adjustments	-	(376.5)	(10.2)	(386.7)
USGAAP	$984.7	$(365.7)	$205.8	$824.8

The statements of income for the 2010 periods reconciled from CGAAP to USGAAP are as follows:

For the three months ended March 31, 2010 millions of Canadian dollars (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Operating revenues				
Electric	O	$337.5	$(337.5)	-
Other	O	3.2	(3.2)	-
Operating revenues	O, P	-	342.8	$342.8
Total operating revenues		340.7	2.1	342.8
Cost of operations				
Fuel for generation and purchased power	Q	181.2	(1.6)	179.6
Fuel for generation and purchased power – affiliates	Q	-	1.6	1.6
Fuel adjustment		(39.4)	-	(39.4)
Operating, maintenance and general	I, P	53.2	1.7	54.9
Provincial grants and taxes		10.0	-	10.0
Depreciation and amortization	B, R	36.6	4.5	41.1
Regulatory amortization	R	4.4	(4.4)	-
Total operating expenses		246.0	1.8	247.8
Income from operations		94.7	0.3	95.0
Other expenses, net	O, S, T	-	3.6	3.6
Financing charges	M, S, T	32.3	(32.3)	-
Interest expense, net	B, S, T	-	26.1	26.1
Income before provision for income taxes		62.4	2.9	65.3
Income tax recovery	B	(0.9)	(1.0)	(1.9)
Net income of Nova Scotia Power Inc.		63.3	3.9	67.2
Dividends on preferred stock	M	-	2.0	2.0
Net income attributable to common shareholders		$63.3	$1.9	$65.2

For the six months ended June 30, 2010 millions of Canadian dollars (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Operating revenues				
Electric	O	$604.5	$(604.5)	-
Other	O	6.8	(6.8)	-
Operating revenues	O, P	-	616.0	$616.0
Total operating revenues		611.3	4.7	616.0
Cost of operations				
Fuel for generation and purchased power	Q	305.5	(6.4)	299.1
Fuel for generation and purchased power – affiliates	Q	-	6.4	6.4
Fuel adjustment		(52.0)	-	(52.0)
Operating, maintenance and general	I, P	111.0	3.9	114.9
Provincial grants and taxes		20.0	-	20.0
Depreciation and amortization	B, R	74.0	9.0	83.0
Regulatory amortization	R	8.8	(8.8)	-
Total operating expenses		467.3	4.1	471.4
Income from operations		144.0	0.6	144.6
Other expenses, net	O, S, T	-	5.9	5.9
Financing charges	M, S, T	63.2	(63.2)	-
Interest expense, net	B, M, S, T	-	52.7	52.7
Income before provision for income taxes		80.8	5.2	86.0
Income tax expense (recovery)	B	2.6	(1.3)	1.3
Net income of Nova Scotia Power Inc.		78.2	6.5	84.7
Dividends on preferred stock	M	-	4.0	4.0
Net income attributable to common shareholders		$78.2	$2.5	$80.7

For the nine months ended September 30, 2010 millions of Canadian dollars (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Operating revenues				
Electric	O	$870.9	$(870.9)	-
Other	O	10.7	(10.7)	-
Operating revenues	O, P	-	888.2	$888.2
Total operating revenues		881.6	6.6	888.2
Cost of operations				
Fuel for generation and purchased power	Q	440.5	(8.0)	432.5
Fuel for generation and purchased power – affiliates	Q	-	8.0	8.0
Fuel adjustment		(75.0)	-	(75.0)
Operating, maintenance and general	I, N, P, T	172.5	5.8	178.3
Provincial grants and taxes		30.0	-	30.0
Depreciation and amortization	B, R	110.9	13.5	124.4
Regulatory amortization	R	13.2	(13.2)	-
Total operating expenses		692.1	6.1	698.2
Income from operations		189.5	0.5	190.0
Other expenses, net	O, S, T	-	7.8	7.8
Financing charges	M, S, T	93.0	(93.0)	-
Interest expense, net	B, M, S, T	-	77.9	77.9
Income before provision for income taxes		96.5	7.8	104.3
Income tax (recovery) expense	B	(4.1)	3.1	(1.0)
Net income of Nova Scotia Power Inc.		100.6	4.7	105.3
Dividends on preferred stock	M	-	6.0	6.0
Net income attributable to common shareholders		$100.6	$(1.3)	$99.3

For the year ended December 31, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Operating revenues				
Electric	O	$1,167.3	$(1,167.3)	-
Other	O	15.4	(15.4)	-
Operating revenues	O, P	-	1,191.4	$1,191.4
Total operating revenues		1,182.7	8.7	1,191.4
Cost of operations				
Fuel for generation and purchased power	Q	586.7	(8.1)	578.6
Fuel for generation and purchased power – affiliates	Q	-	8.1	8.1
Fuel adjustment		(99.0)	-	(99.0)
Operating, maintenance and general	I, N, P, T	237.5	8.3	245.8
Provincial grants and taxes		40.1	-	40.1
Depreciation and amortization	B, R	150.8	37.3	188.1
Regulatory amortization	R	36.9	(36.9)	-
Total operating expenses		953.0	8.7	961.7
Income from operations		229.7	-	229.7
Other expenses, net	O, S, T	-	11.3	11.3
Financing charges	M, S, T	125.8	(125.8)	-
Interest expense, net	B, M, S, T	-	104.7	104.7
Income before provision for income taxes		103.9	9.8	113.7
Income tax (recovery) expense	B	(17.4)	4.0	(13.4)
Net income of Nova Scotia Power Inc.		121.3	5.8	127.1
Dividends on preferred stock	M	-	7.9	7.9
Net income attributable to common shareholders		$121.3	$(2.1)	$119.2

The statements of cash flows for the 2010 periods reconciled from CGAAP to USGAAP are as follows:

For the three months ended March 31, 2010 millions of Canadian dollars (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Net cash used in operating activities	M, S	$(17.3)	$3.7	$(13.6)
Net cash used in investing activities	S	(50.0)	(1.7)	(51.7)
Net cash provided by financing activities	M	67.3	(2.0)	65.3
Net change in cash		-	-	-
Cash, beginning of period		0.3	-	0.3
Cash, end of period		$0.3	-	$0.3

For the six months ended June 30, 2010 millions of Canadian dollars (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Net cash provided by operating activities	M, S	$43.2	$7.4	$50.6
Net cash used in investing activities	S	(210.6)	(3.4)	(214.0)
Net cash provided by financing activities	M	167.4	(4.0)	163.4
Net change in cash		-	-	-
Cash, beginning of period		0.3	-	0.3
Cash, end of period		$0.3	-	$0.3

For the nine months ended September 30, 2010 millions of Canadian dollars (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Net cash provided by operating activities	M, S	$139.8	$12.5	$152.3
Net cash used in investing activities	S	(352.8)	(6.5)	(359.3)
Net cash provided by financing activities	M	213.0	(6.0)	207.0
Net change in cash		-	-	-
Cash, beginning of period		0.3	-	0.3
Cash, end of period		$0.3	-	$0.3

For the year ended December 31, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Net cash provided by operating activities	B, M, S	$300.2	$17.1	$317.3
Net cash used in investing activities	B, S	(533.3)	(9.2)	(542.5)
Net cash provided by financing activities	M	233.1	(7.9)	225.2
Net change in cash		-	-	-
Cash, beginning of period		0.3	-	0.3
Cash, end of period		$0.3	-	$0.3

NOTES TO THE TRANSITIONAL ADJUSTMENTS

Under USGAAP, the Company is (i) measuring certain assets, liabilities, revenues and expenses differently than it had been under CGAAP (see details on each measurement change below); and (ii) disclosing certain assets, liabilities, revenues and expenses on different lines in the financial statements than they had been under CGAAP (see details on each classification change below).

A. Offsetting (measurement difference)

Certain items on the balance sheets are being offset where a legal right of setoff exists. Differences exist between CGAAP and USGAAP in defining what balances may be offset.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Receivables, net	$(0.9)	-
Accounts payable	(0.9)	-

B. Income taxes (measurement difference)

In addition to the tax effects of other transition adjustments, the following are included in the income tax adjustments.

Investment tax credits ("ITCs")

Under CGAAP, the Company recognized ITCs as a reduction from the related expenditures where there was reasonable assurance of collection. Under USGAAP, the Company recognizes ITCs as a reduction to income tax expense in the current and future periods to the extent that realization of such benefit is more likely than not.

Tax rates

Under CGAAP, the Company measured income taxes using substantively enacted income tax rates. Under USGAAP, the Company uses enacted income tax rates. NSPI recognized an income tax liability under USGAAP for the difference between the enacted tax rates and the substantively enacted tax rates for the Part VI.1 tax deduction related to dividends on preferred stock.

Uncertain tax positions

Under CGAAP, the Company recognizes the benefit of an uncertain tax position when it is probable of being sustained.

Under USGAAP, the Company recognizes the benefit of an uncertain tax position only when it is more likely than not that such a position will be sustained by the taxing authorities based on the technical merits of the position. The current and deferred income tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Current assets		
Income taxes receivable	-	$(6.3)
Deferred income taxes	$(22.3)	(4.1)
Property, plant and equipment	1.0	1.3
Other assets		
Deferred income taxes	61.4	16.8
Regulatory assets	(25.2)	(136.9)
Other	1.2	0.7
Current liabilities		
Income taxes payable	2.1	-
Deferred income taxes	-	3.4
Regulatory liabilities	4.7	3.0
Other current liabilities	1.3	1.2
Long-term liabilities		
Deferred income taxes	(52.0)	(163.1)
Regulatory liabilities	61.2	32.4
Equity		
Retained earnings	(1.2)	(5.4)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Depreciation and amortization	$0.1	$0.2	$0.3	$0.4
Interest expense, net	(0.3)	(0.3)	(0.4)	(0.2)
Income tax (recovery) expense	(1.0)	(1.3)	3.1	4.0

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the effect on the Statements of Cash Flows is as follows:

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Net cash provided by operating activities	-	-	-	$0.3
Net cash used in investing activities	-	-	-	(0.3)

C. Derivatives (classification change)

Under CGAAP, the Company was disclosing its derivatives in valid hedging relationships and held-for-trading derivatives as separate line items on the balance sheet. Under USGAAP, the Company has included these balances together in “Derivative instruments”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Current assets		
Derivative instruments	$28.3	$31.0
Derivatives in a valid hedging relationship	(19.4)	(24.7)
Held-for-trading derivatives	(8.9)	(6.3)
Other assets		
Derivative instruments	36.0	29.0
Derivatives in a valid hedging relationship	(29.8)	(20.8)
Held-for-trading derivatives	(6.2)	(8.2)
Current liabilities		
Derivative instruments	65.2	23.0
Derivatives in a valid hedging relationship	(53.0)	(2.2)
Held-for-trading derivatives	(12.2)	(20.8)
Long-term liabilities		
Derivative instruments	21.3	11.2
Derivatives in a valid hedging relationship	(20.0)	(9.4)
Held-for-trading derivatives	(1.3)	(1.8)

D. Regulatory assets and liabilities (classification change)

Under CGAAP, the Company was disclosing its regulatory assets and liabilities in other assets and liabilities respectively. Under USGAAP, the Company discloses its regulatory assets and liabilities as separate line items on the balance sheet.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Current assets		
Regulatory assets	$46.8	$44.9
Other assets		
Regulatory assets	198.2	357.2
Other	(245.0)	(402.1)
Current liabilities		
Regulatory liabilities	18.8	20.8
Long-term liabilities		
Regulatory liabilities	(3.9)	8.1
Other long-term liabilities	(14.9)	(28.9)

E. Hedging (measurement change)

Effective for 2011, NSPI implemented an amended hedge accounting policy, which was approved by the UARB. The amended policy resulted from stakeholder requests to simplify the accounting for derivatives used to manage risk and to alleviate any USGAAP issues which would result in increased income volatility. The amended policy is applied retrospectively with restatement of prior periods with the exception of prior period income, and requires regulatory deferral for commodity, foreign exchange and interest derivatives documented as economic hedges and for physical contracts that do not qualify for the NPNS exception under USGAAP.

As a result of the amended accounting policy, NSPI receives regulatory deferral for any changes in fair value on derivatives documented as economic hedges.

As at January 1, 2010 and December 31, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Current assets		
Regulatory assets	$75.9	$26.9
Other assets		
Regulatory assets	20.0	12.2
Current liabilities		
Regulatory liabilities	22.1	28.6
Long-term liabilities		
Regulatory liabilities	29.8	21.2
Equity		
Accumulated other comprehensive income (loss)	44.0	(10.7)

F. Current other assets and liabilities (classification change)

Under CGAAP, the Company was disclosing its other assets and liabilities on the balance sheet as long-term. Under USGAAP, the Company has included the current portion of these balances in “Other current assets” and “Other current liabilities”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other current assets	$1.5	$1.8
Other, included in other assets	(1.5)	(1.8)
Other current liabilities	1.3	0.9
Other long-term liabilities	(1.3)	(0.9)

G. Construction work-in-progress (classification change)

Under CGAAP, the Company was disclosing its construction work-in-progress (“CWIP”) as a separate line item on the balance sheet. Under USGAAP, the Company has included this balance in “Property, plant and equipment” and will disclose its CWIP balance annually in the notes to the December 31 financial statements.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Property, plant and equipment	$152.8	$279.2
Construction work-in-progress	(152.8)	(279.2)

H. Intangibles (classification change)

Under CGAAP, the Company was disclosing its intangibles as a separate line item on the balance sheet. Under USGAAP, the Company has included this balance in “Other” as part of “Other assets”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other, included in other assets	$65.7	$72.5
Intangibles	(65.7)	(72.5)

I. Pension and other post-retirement benefits (measurement change)

Under CGAAP, the Company disclosed, but did not recognize, its unamortized gains and losses, its past service costs, and its unamortized transitional obligation associated with pension and other post-retirement benefits. Under USGAAP, the Company has recognized its unfunded pension obligation as a liability; the unamortized gains and losses and past service costs are recognized in “Accumulated other comprehensive loss”; and the unamortized transitional obligation previously determined under CGAAP is recognized in “Retained earnings”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other assets		
Other	$(94.3)	$(110.7)
Current liabilities		
Pension and post-retirement liabilities	8.3	8.2
Long-term liabilities		
Pension and post-retirement liabilities	221.2	314.7
Other long-term liabilities	(60.9)	(63.4)
Equity		
Accumulated other comprehensive loss	(256.1)	(365.7)
Retained earnings	(6.8)	(4.5)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Operating, maintenance and general	$(0.6)	$(1.1)	$(1.7)	$(2.3)

J. Issue costs

Classification change

Under CGAAP, debt financing costs, premiums and discounts were netted against long-term debt. Under USGAAP, debt financing costs are included in “Other” as part of “Other assets”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other, included in other assets	$10.5	$12.6
Long-term debt	10.5	12.6

Measurement Change

Under CGAAP, the straight-line method of amortizing debt financing costs, premiums and discounts was used to approximate the effective interest method. Under USGAAP, the straight-line method is not appropriate so the effective interest method has been adopted.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other, included in other assets	$1.1	$1.1
Long-term debt	2.2	2.2
Retained earnings	(1.1)	(1.1)

K. Accounts payable (classification change)

Under CGAAP, trade and non-trade payables were recognized in accounts payable and accrued charges. Under USGAAP, trade payables are recognized in “Accounts payable” and non-trade payables are recognized in “Other current liabilities”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Accounts payable	$152.6	$157.9
Accounts payable and accrued charges	(213.9)	(221.3)
Other current liabilities	61.3	63.2
Other long-term liabilities	-	0.2

L. Dividends payable (classification change)

Under CGAAP, the Company was disclosing dividends payable as a separate line item on the balance sheet. Under USGAAP, the Company has included this balance in “Other current liabilities”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Dividends payable	$(1.7)	$(1.7)
Other current liabilities	1.7	1.7

M. Redeemable preferred stock (measurement change)

Under CGAAP, NSPI's redeemable preferred stock were classified as a liability; dividends on preferred stock were classified as an expense in the statement of income and were accrued monthly; and issuance costs were deferred on the balance sheet as a deferred financing charge and amortized to income over the life of the redeemable preferred stock.

Under USGAAP NSPI's redeemable preferred stock are classified as mezzanine equity as the redeemable preferred stock do not meet the USGAAP definition of a liability; dividends on preferred stock are deducted from retained earnings and are accrued as declared; and issuance costs are netted against the redeemable preferred stock on the balance sheet and are not amortized.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other current liabilities	$0.3	$0.3
Long-term debt	0.7	0.6
Preferred shares	(135.0)	(135.0)
Redeemable preferred stock	132.2	132.2
Retained earnings	1.8	1.9

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Financing charges	$(2.0)	$(4.0)	$(6.0)	$(7.9)
Interest expense, net	-	(0.1)	(0.1)	(0.1)
Dividends on preferred stock	2.0	4.0	6.0	7.9

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the effect on the Statements of Cash Flows is as follows:

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Net cash provided by operating activities	$2.0	$4.0	$6.0	$7.9
Net cash used in financing activities	(2.0)	(4.0)	(6.0)	(7.9)

N. Stock-based compensation

Employee Common Share Purchase Plan

Under USGAAP, the Company's employee common share purchase plan is considered compensatory and the Company's contribution to the plan should be recognized. Under CGAAP, the Company was recognizing the amount of its contribution in excess of 5 percent of the average market price of the shares.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Due to related parties	$0.9	$1.1
Retained earnings	(0.9)	(1.1)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Operating, maintenance and general	-	-	$0.1	$0.2

O. Revenue

Under CGAAP, revenue was recognized in electric and other revenue. Under USGAAP, electric and other revenue is recognized in “Operating revenues” and “Other expenses, net”.

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Electric revenue	$(337.5)	$(604.5)	$(870.9)	$(1,167.3)
Other revenue	(3.2)	(6.8)	(10.7)	(15.4)
Operating revenues	340.6	611.0	881.0	1,181.2
Other expenses, net	(0.1)	(0.3)	(0.6)	(1.5)

P. Netting of certain revenues and expenses

Under CGAAP, the Company was netting certain revenues and expenses in its statements of income. Under USGAAP, revenues are classified on a gross or net basis depending on whether the Company is acting as the principal or an agent in the transaction. The adoption of USGAAP has resulted in certain revenue transactions disclosed on a net basis under CGAAP to be presented on a gross basis under USGAAP.

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Operating revenues	$2.3	$5.0	$7.3	$10.2
Operating, maintenance and general	2.3	5.0	7.3	10.2

Q. Fuel for generation and purchased power

Under CGAAP, all the fuel for generation and purchased power was recognized as such. Under USGAAP, fuel for generation and purchased power purchased from or sold to affiliates is recognized in a separate line item.

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Fuel for generation and purchased power	$(1.6)	$(6.4)	$(8.0)	$(8.1)
Fuel for generation and purchased power – affiliates	1.6	6.4	8.0	8.1

R. Regulatory amortization

Under CGAAP, regulatory amortization was disclosed as a separate line item. Under USGAAP, regulatory amortization is included in “Depreciation and amortization”.

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Depreciation and amortization	$4.4	$8.8	$13.2	$36.9
Regulatory amortization	(4.4)	(8.8)	(13.2)	(36.9)

S. Allowance for funds used during construction

Under CGAAP, AFUDC was included in financing charges. Under USGAAP, allowance for equity funds used during construction is included in “Other expenses, net” and allowance for borrowed funds used during construction is netted against “Interest expense, net”.

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Other expenses, net	$(1.8)	$(4.1)	$(8.1)	$(12.0)
Financing charges expenses	3.5	7.5	14.6	20.9
Interest expense, net	(1.7)	(3.4)	(6.5)	(8.9)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the effect on the Statements of Cash Flows is as follows:

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Net cash provided by operating activities	$1.7	$3.4	$6.5	$8.9
Net cash used in investing activities	(1.7)	(3.4)	(6.5)	(8.9)

T. Interest expense

Under CGAAP, interest expense, amortization of defeasance costs, and foreign exchange gains and losses were included in financing charges. Under USGAAP, interest expense is disclosed in a separate line item and amortization of defeasance costs and foreign exchange gains and losses are included in “Other expenses, net”.

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Operating, maintenance and general	-	-	$0.1	$0.2
Other expenses, net	$5.6	$10.3	16.5	24.8
Financing charges	(33.8)	(66.7)	(101.5)	(138.9)
Interest expense, net	28.2	56.4	84.9	113.9

Emera

Management's Discussion & Analysis

As at February 10, 2012

Management's Discussion and Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its primary subsidiaries and investments ("Emera") during the fourth quarter of 2011 relative to 2010; and the full year 2011 relative to 2010 and 2009; and its financial position as at December 31, 2011 relative to 2010. To enhance shareholders' understanding, certain multi-year historical financial and statistical information is presented. Throughout this discussion, "Emera Incorporated", "Emera" and "Company" refer to Emera Incorporated and all of its consolidated subsidiaries and investments.

Effective January 1, 2011, Emera changed the basis of presentation of its financial statements, including the application of rate-regulated accounting policies for Emera's rate-regulated subsidiaries, from Canadian Generally Accepted Accounting Principles ("CGAAP") to United States Generally Accepted Accounting Principles ("USGAAP") for information derived from the Consolidated Statements of Income for the three months and year ended December 31, 2011 and Consolidated Balance Sheets as at December 31, 2011. Financial information for 2010 and 2009 has been adjusted to reflect USGAAP and is clearly labeled "adjusted".

This discussion and analysis should be read in conjunction with the Emera Incorporated annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2011, prepared in accordance with USGAAP.

The accounting policies used by Emera's rate-regulated entities may differ from those used by Emera's non rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenue and expenses. Emera's rate-regulated subsidiaries include:

Emera Rate-Regulated Subsidiary	Accounting Policies Approved/Examined By
Nova Scotia Power Inc. ("NSPI")	Nova Scotia Utility and Review Board ("UARB")
Bangor Hydro Electric Company ("Bangor Hydro")	Maine Public Utilities Commissions ("MPUC") and the Federal Energy Regulatory Commission ("FERC")
Maine Public Service Company ("MPS")	MPUC and FERC
Barbados Light & Power Company Limited ("BLPC")	Fair Trading Commission, Barbados
Grand Bahama Power Company Limited ("GBPC")	The Grand Bahama Port Authority ("GBPA")
Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline")	National Energy Board ("NEB")

All amounts are in Canadian dollars ("CAD") except for the Maine Utility Operations section of the MD&A, which is reported in US dollars ("USD") unless otherwise stated.

Additional information related to Emera, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com or on EDGAR at www.sec.gov.

Forward Looking Information

This MD&A contains “forward-looking information” within the meaning of applicable Canadian securities laws and “forward-looking statements” within the meaning of the United States Private Securities Litigation Reform Act of 1995 (collectively, “forward-looking information”). The words “anticipates”, “believes”, “could”, “estimates”, “expects”, “intends”, “may”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this MD&A includes statements which reflect the current view with respect to the Company’s objectives, plans, financial and operating performance, business prospects and opportunities. The forward-looking information reflects management’s current beliefs and is based on information currently available to Emera’s management and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the times at which, such events, performance or results will be achieved.

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations are discussed in the Outlook section of the MD&A and may also include: regulatory risk; operating and maintenance risks; economic conditions; availability and price of energy and other commodities; capital resources and liquidity risk; weather; commodity price risk; competitive pressures; construction; derivative financial instruments and hedging availability and cost of financing; interest rate risk; counterparty risk; competitiveness of electricity as an energy source; commodity supply; environmental risks; foreign exchange; regulatory and government decisions including changes to environmental, financial reporting and tax legislation; loss of service area; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on forward-looking information as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, Emera undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

Structure of MD&A

This MD&A begins with an Introduction and Strategic Overview; followed by the Consolidated Financial Review of the Statements of Income, Balance Sheets, Statements of Cash Flows, and outstanding share data; then presents information separately on Emera's consolidated subsidiaries and investments, specifically:

- NSPI;
- Maine Utility Operations (Bangor Hydro, MPS and its parent company, Maine and Maritimes Corporation ("MAM"));
- Caribbean Utility Operations (BLPC and its parent company, Light & Power Holdings Ltd. ("LPH"), GBPC and St. Lucia Electricity Services Limited ("Lucelec"));
- Pipelines (Brunswick Pipeline and Maritimes & Northeast Pipeline ("M&NP"));
- Other operations and investments are grouped and discussed under Services, Renewables and Other Investments ("SRO") and include:
    - Emera Energy Inc. ("Emera Energy") includes (Emera Energy Services, Bayside Power Limited Partnership ("Bayside Power"), Bear Swamp Power Company LLC. ("Bear Swamp")),
    - Emera Utility Services Inc. ("EUS"),
    - Emera Newfoundland & Labrador Holdings Inc. ("ENL"),
    - Algonquin Power & Utilities Corp. ("APUC"),
    - California Pacific Utilities Ventures, LLC ("CPUV") and
    - Atlantic Hydrogen Inc. ("AHI"); and
- Corporate

The Outlook, Liquidity and Capital Resources, Pension Funding, Off-Balance Sheet Arrangements, Transactions with Related Parties, Dividends and Payout Ratios, Risk Management and Financial Instruments, Disclosure and Internal Controls, Significant Accounting Policies and Critical Accounting Estimates, Changes in Accounting Policies and Practices, Summary of Quarterly Results, Operating Statistics and Three Year Financial Summary sections of the MD&A are presented on a consolidated basis.

INTRODUCTION AND STRATEGIC OVERVIEW

Emera Incorporated is an energy and services company with $6.9 billion in assets. The Company invests in electricity generation, transmission and distribution, gas transmission and utility energy services. Emera's strategy is focused on the transformation of the electricity industry to cleaner generation and the delivery of that cleaner energy to market. Emera has interests throughout northeastern North America, in three Caribbean countries and in California.

Emera's goal is to increase earnings per share by an average of 4 percent to 6 percent annually and to build and diversify its income base with a focus on cleaner energy in its markets. Emera will continue to build its existing business and will leverage its core strength in the electricity business to pursue acquisitions and greenfield development opportunities in regulated electricity transmission, distribution and lower risk generation.

Approximately 85 percent of Emera's net income is earned by its rate-regulated subsidiaries. The success of these subsidiaries is integral to the creation of shareholder value, providing strong, predictable income and cash flows to fund dividends and reinvestment.

Non-GAAP Financial Measures

Emera uses financial measures that do not have a standardized meaning under USGAAP.

NSPI

"Electric margin" is a non-GAAP financial measure used by NSPI and is defined as "Electric revenues" less "Regulated fuel for generation and purchased power" and "Regulated fuel for generation and purchased power – affiliates", net of the "Regulated fuel adjustment", fuel-related foreign exchange gains or losses and other fuel-related costs. This measure is disclosed as management believes it provides useful information regarding the effect of the fuel adjustment mechanism ("FAM") on NSPI's operations. Electric margin is discussed further in the Consolidated Financial Review – Consolidated Financial Highlights section and the NSPI – Review of 2011 section.

Services, Renewables and Other Investments

"Net income applicable to common shares, absent the Bear Swamp after-tax mark-to-market adjustment", "Earnings per common share – basic, absent the Bear Swamp after-tax mark-to-market adjustment", "Contribution to consolidated net income, absent the Bear Swamp after-tax mark-to-market adjustment" and "Contribution to consolidated net earnings per common share, absent the Bear Swamp after-tax mark-to-market adjustment" are non-GAAP financial measures used by Emera. Management discloses these financial measures as it believes the inclusion of the mark-to-market adjustment in Bear Swamp's financial results does not accurately reflect its operational performance. The adjustment is discussed further in the Consolidated Financial Review – Consolidated Financial Highlights section, Consolidated Financial Review – Significant Items section, and Services, Renewables and Other Investments – Review of 2011 section.

Earnings before interest and taxes ("EBIT") is a non-GAAP financial measure used by Emera and is defined as Income before "Interest expense, net" and "Income tax expense (recovery)". This measure is disclosed as management believes it provides useful information on how it views the operations of Emera Energy and EUS. EBIT is discussed in the Services, Renewables and Other Investments – Review of 2011 section.

CONSOLIDATED FINANCIAL REVIEW

Consolidated Financial Highlights

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Operating revenues	**$512.0**	$408.9	**$2,064.4**	$1,606.1	$1,490.1
Net income attributable to common shareholders	**46.8**	24.1	**241.1**	190.7	186.3
Earnings per common share – basic	**$0.38**	$0.21	**$1.99**	$1.67	$1.65
Earnings per common share – diluted	**$0.38**	$0.21	**$1.97**	$1.65	$1.61
Dividends per common share declared	**-**	-	**$1.3125**	$1.1625	$1.0300

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
Operating Unit Contributions	**2011**	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
NSPI	**$22.2**	$19.9	**$123.5**	$119.2	$110.8
Maine Utility Operations	**9.8**	7.8	**37.0**	31.9	27.5
Caribbean Utility Operations	**3.1**	(7.7)	**46.8**	19.8	2.9
Pipelines	**6.9**	8.0	**27.9**	28.9	30.1
Services, Renewables and Other Investments	**6.0**	1.8	**27.0**	8.6	14.7
Corporate	**(1.2)**	(5.7)	**(21.1)**	(17.7)	0.3
Net income attributable to common shareholders	**$46.8**	$24.1	**$241.1**	$190.7	$186.3
Net income applicable to common shares, absent the Bear Swamp after-tax mark-to-market adjustment	**$47.5**	$26.7	**$241.9**	$199.3	$185.6
Earnings per common share – basic	**$0.38**	$0.21	**$1.99**	$1.67	$1.65
Earnings per common share – basic, absent the Bear Swamp after-tax mark-to-market adjustment	**$0.39**	$0.23	**$2.00**	$1.75	$1.64

	As at December 31		
	2011	2010 (adjusted)	2009 (adjusted)
Total assets	**$6,923.6**	$6,079.0	$5,247.3
Total long-term liabilities	**4,298.2**	3,941.7	2,955.8

Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Consolidated net income attributable to common shareholders – 2009 (adjusted)		**$186.3**
NSPI – Increased net income primarily due to decreased income taxes partially offset by increased operating, maintenance and general expenses ("OM&G") and decreased electric margin		8.4
Maine Utility Operations – Increased net income primarily due to transmission rate increases and increased transmission pool revenue related to recovery of regionally funded transmission investments, partially offset by a stronger average CAD in 2010		4.4
Caribbean Utility Operations – Increased primarily due to initial investment in LPH offset in part by GBPC acquisition-related costs		16.9
Pipelines – Decreased net income primarily due to decreased income from M&NP equity investment		(1.2)
Services, Renewables and Other Investments – Decreased net income primarily due to an unfavorable change in the fair value of the net derivatives in Bear Swamp, partially offset by increased earnings in Emera Energy and EUS		(6.1)
Corporate – Increased primarily due to increased interest expense and acquisition-related costs		(18.0)
Consolidated net income attributable to common shareholders – 2010 (adjusted)	**$24.1**	**$190.7**
NSPI – Increased net income primarily due to increased income tax recovery, partially offset by decreased electric margin and increased OM&G expenses	2.3	4.3
Maine Utility Operations – Increased net income during the quarter primarily due to lower OM&G expenses in Bangor Hydro, partially offset by a decrease in electric revenue; increased net income year-over-year primarily due to the recovery of a greater amount of regionally funded transmission investments, lower OM&G expenses and the acquisition of MAM in Q4 2010	2.0	5.1
Caribbean Utility Operations – Increased net income during the quarter primarily due to increased ownership of both GBPC and LPH. Year-over-year increase also reflects incremental $5.8 million gain on the acquisition of LPH recorded in 2011 versus 2010; and increased earnings in GBPC	10.8	27.0
Pipelines – Decreased net income primarily due to decreased income from M&NP equity investment	(1.1)	(1.0)
Services, Renewables and Other Investments – Increased net income during the quarter due primarily to a positive change in the fair value of the net derivatives in Bear Swamp. Increased year-over-year net income primarily due to gain on APUC subscription receipts and a positive change in the fair value of the net derivatives in Bear Swamp	4.2	18.4
Corporate – Decreased costs during the quarter primarily due to decreased deferred compensation, lower business acquisition costs and foreign exchange gains; Increased costs year-over-year primarily due to higher financing costs partially offset by a higher income tax recovery	4.5	(3.4)
Consolidated net income attributable to common shareholders – 2011	**$46.8**	**$241.1**

Basic earnings per share were $0.38 in Q4 2011 compared to $0.21 in Q4 2010 (adjusted); and $1.99 for the full year 2011 compared to $1.67 in 2010 (adjusted) and $1.65 in 2009 (adjusted).

Developments

Emera

Strategic Investment Agreement with Algonquin Power & Utilities Corp.

Emera has a Strategic Investment Agreement ("SIA") with Algonquin Power & Utilities Corp ("APUC" or "Algonquin") which establishes how Emera and APUC will work together to pursue specific strategic investments of mutual benefit. The SIA outlines "areas of pursuit" for both Emera and APUC. For Emera, these include investment opportunities related to regulated renewable generation and transmission projects within its service territories, and large electric utilities. For Algonquin, these include investment opportunities relating to unregulated renewable generation, small electric utilities and gas distribution utilities. Emera is committed to working with Algonquin on opportunities that fit within Algonquin's "areas of pursuit".

The SIA also provides for Emera to acquire up to 25% of APUC through the purchase of common shares issued by APUC to fund certain investment opportunities developed in conjunction with Emera under the SIA. The share purchases are executed via the acquisition of subscription receipts in exchange for promissory notes at an agreed upon price, which are then exchangeable into common shares when certain conditions relating to specific transactions are met. The acquisition of subscription receipts is subject to approvals required under applicable laws, including the rules of the Toronto Stock Exchange ("TSX").

Emera and Algonquin are currently working to complete two such transactions, as set out below:

California Pacific Transaction
On January 1, 2011, Emera and APUC closed their acquisition of the California-based electricity distribution and related generation assets of NV Energy, Inc. for total consideration of $136.8 million CAD ($137.5 million USD), subject to final adjustments. A new utility company, California Pacific Electric Company, LLC ("California Pacific") was established to own and operate the assets. California Pacific is wholly-owned by California Pacific Utilities Ventures LLC ("CPUV"), which in turn is owned 49.999 percent by Emera and 50.001 percent by APUC. Emera paid $31.8 million CAD ($31.2 million USD) for its interest in the common shares of CPUV.

Pursuant to an April 2009 Subscription Receipts Agreement with APUC, upon the closing of the California Pacific transaction in Q1 2011, as described above, Emera exchanged subscription receipts acquired in 2009 into 8.523 million APUC common shares issued at $3.25 per share, resulting in an after-tax gain of $12.8 million. This gain is recorded in "Other income (expenses), net" on Emera's Consolidated Statements of Income for the year ended December 31, 2011. As a result of this transaction, and APUC's subsequent conversion of certain of its debentures to equity, Emera owns an approximate 6.2 percent equity interest in APUC as at December 31, 2011.

Consistent with the framework established by the SIA referred to above, in April 2011 Emera agreed to sell its 49.999 percent direct ownership in CPUV, to APUC for $38.8 million, subject to applicable regulatory approval. In connection with this sale, Emera purchased 8.211 million subscription receipts from APUC at an issue price of $4.72 each for a total purchase price of $38.8 million. Emera has issued two promissory notes to APUC in exchange for these subscription receipts, the proceeds of which will be used by APUC to pay Emera for its CPUV ownership interest. The subscription receipts are convertible to 8.211 million APUC shares in two tranches. 4.79 million will be exchanged for APUC shares following applicable regulatory approval of the CPUV ownership transfer, including the MPUC approval referenced below under the heading "APUC Withdrawal from First Wind Transaction". The remainder will be exchanged upon completion of California Pacific's first rate case, expected in 2012. The purchase of subscription receipts has received final Toronto Stock Exchange approval.

New Hampshire Transaction
On March 25, 2011, Emera purchased 12 million subscription receipts from APUC at an issue price of $5.00 each for a total purchase price of $60 million. Emera issued a promissory note in exchange for the subscription receipts. The subscription receipts are convertible to 12 million APUC common shares upon the acquisition by APUC's regulated subsidiary, Liberty Energy Utilities Co., of all issued and outstanding shares of Granite State Electric Company and Energy North Natural Gas Inc., two regulated utilities, currently owned by National Grid USA (the "New Hampshire Transaction"). The acquisitions are subject to applicable regulatory approvals and the conversion of subscription receipts is subject to the MPUC approval referenced below under the heading "APUC Withdrawal from First Wind Transaction". The purchase of subscription receipts has received final Toronto Stock Exchange approval.

Assuming the completion of the sale of CPUV to APUC and the New Hampshire Transactions, which are expected in 2012, the associated conversion of the subscription receipts to APUC common shares, and the exercise of Emera's anti-dilution rights, Emera's ownership interest in APUC will increase to approximately 18 percent.

The table below summarizes the aforementioned transactions:

Underlying Transaction	No. of shares/subscription receipts	Price per subscription receipt	Quarter closed / expected to close
Acquisition of California Pacific	8,523,000	$3.25	Q1 2011
New Hampshire Transaction	12,000,000	$5.00	Q1 2012
Sale of California Pacific	8,211,000	$4.72	Q1 2012

APUC Withdrawal from First Wind Transaction

Emera and Algonquin had planned to partner with First Wind Holdings LLC ("First Wind") to own 370 MW of wind energy projects in the northeastern United States. As regulator of Emera's Maine utilities, the MPUC must approve any new affiliation (defined as an investment that is over 10%) between Emera and certain enterprises, including those that own generation in the restructured Maine market, such as First Wind and Algonquin. On January 13, 2012, MPUC staff issued a report recommending the Commission not approve the First Wind transaction, nor Emera's plan to increase its ownership in Algonquin beyond 10%. Emera disagrees with the conclusions in the report, and outlined its concerns in a formal response filed January 23, 2012.

On January 27, 2012, APUC announced it would not be proceeding with its 12.5% investment in First Wind, citing the longer than anticipated regulatory process in Maine, and other transactions it became involved with since the First Wind acquisition process commenced. Emera plans to continue to pursue the First Wind transaction, as detailed below. Both Emera and Algonquin remain committed to the SIA, and are hopeful that APUC removing itself from the First Wind transaction will address the MPUC's concerns.

The MPUC was scheduled to render a formal decision on these matters on January 31, 2012. That decision has been delayed, but is expected to be issued in the first quarter of 2012.

Emera had purchased 6.9 million subscription receipts for $5.37 each on July 29, 2011 in connection with this transaction. These will now terminate, as will the $37 million promissory note, Emera had issued in exchange for the subscription receipts.

Emera's Investment in First Wind

Subject to the approval of the MPUC as discussed above, Emera is partnering with First Wind to own 370 MW of wind energy facilities in the northeastern United States. These assets will become part of a new operating company, owned 51 percent by First Wind, and 49 percent by a new Emera owned entity, Northeast Wind. Northeast Wind will invest a total of approximately $353 million USD to acquire its 49 percent interest in the operating company, including a $150 million USD loan. The acquisition requires certain state and federal regulatory approvals, all of which have been obtained with the exception of the MPUC approval as noted above. Emera will finance the transaction through existing credit facilities subject to lender approval.

Issue of Medium-Term Notes

On December 13, 2011, Emera completed the issue of $250 million Series H Medium-Term Notes. The Series H Notes bear interest at a rate of 2.96 percent and yield 2.969 percent per annum until December 13, 2016.

The net proceeds of the offering were used to repay short-term borrowings and for general corporate purposes.

Increase in Common Share Dividend

On September 23, 2011, Emera's Board of Directors approved an increase in the annual common share dividend rate from $1.30 to $1.35, and accordingly declared a quarterly dividend of $0.3375 per common share.

Common Share Financing

On March 16, 2011, Emera completed an offering of 6,359,500 common shares, including the exercise of the over-allotment option of 829,500 common shares, at $31.70 per common share, for net proceeds of approximately $196.0 million. The net proceeds of the offering were used for general corporate purposes, including repayment of indebtedness under Emera's credit facility.

The Barbados Light & Power Company Limited

On December 20, 2010, Emera offered to purchase all issued and outstanding common stock of LPH, the parent company of BLPC, at a cash price of $25.70 Barbadian dollars per share. The offer closed on January 24, 2011, and on January 25, 2011, Emera purchased 7.2 million shares representing an additional interest of 41.8 percent. With this additional investment of $92.6 million, Emera became the majority shareholder of LPH, with a total interest of 80.1 percent. Based on the purchase price allocation, as determined under USGAAP, the fair value of the net assets acquired in the LPH acquisition exceeded the purchase price by $28.2 million, which Emera has recorded as a non-taxable gain in "Other income (expenses), net" on Emera's Consolidated Statements of Income for the year ended December 31, 2011. Further information on the gain is provided in the Consolidated Financial Review – Significant Items section.

US Securities and Exchange Commission Registration

On October 5, 2011, Emera registered its common shares under the US Securities Exchange Act of 1934, as amended ("the Exchange Act").

On February 23, 2011, Emera registered its debt securities, first preferred shares and second preferred shares under the US Securities Act of 1933, as amended.

NSPI

UARB Decision on 2012 Fuel Adjustment Mechanism

On December 19, 2011, the UARB approved NSPI's customer rates associated with the 2012 FAM adjustment related to the recovery of prior period fuel costs. The recovery of these costs began January 1, 2012. The approved customer rates seek to recover $69.0 million of prior years' unrecovered fuel costs in 2012.

United States Securities and Exchange Commission Registration Status

Consistent with several Canadian industry peers, NSPI requested and received an exemption from Canadian securities regulators allowing it to continue to report its financial results in accordance with USGAAP. On December 12, 2011, NSPI filed with the United States Securities Exchange Commission ("SEC"), to remove from registration all unsold debt securities as of that date. NSPI also filed to terminate its reporting obligations under Section 15(d) of the Exchange Act.

2012 General Rate Decision

On May 13, 2011, NSPI filed a General Rate Application ("GRA") with the UARB requesting an average 7.3 percent rate increase across all customer classes effective January 1, 2012. On November 29, 2011, the UARB approved a settlement agreement between NSPI and customer representatives which resulted in an average rate increase of 5.1 percent for all customers, effective January 1, 2012. Rates were approved based on a 9.2 percent return on equity ("ROE"), applied to a 37.5 percent common equity component with a target earnings range of 9.1 percent to 9.5 percent on maximum actual equity of 40 percent.

NewPage Port Hawkesbury Corp.

On September 9, 2011, NewPage Port Hawkesbury Corp. ("NewPage"), NSPI's largest customer was granted creditor protection under the Companies' Creditors Arrangement Act ("CCAA"). On September 7, 2011, NewPage Group Inc., NewPage's corporate parent, commenced a voluntary case under Chapter 11 of the United States Bankruptcy Code. NewPage has suspended operations and is actively seeking a buyer for its facility. In light of this, the 2012 General Rate Decision, approved by the UARB, provides for any unrecovered non-fuel electric charges in 2012 related to this customer to be deferred and recovered beginning in 2013. NewPage was also responsible for the engineering, procurement and construction of a 60 MW biomass facility in Port Hawkesbury, Nova Scotia for NSPI. NSPI is proceeding with this project and has assumed full project management responsibilities.

Canadian Environmental Regulations

On August 19, 2011, Environment Canada announced proposed regulations for a new national carbon dioxide framework for the electricity sector in Canada. These proposed regulations would apply to new coal-fired electricity generation units; and existing coal-fired electricity generation units that have reached the end of their deemed economic life of forty-five years after commissioning. These proposed regulations will be effective July 1, 2015. Nova Scotia's existing greenhouse gas regulations require reductions in NSPI's emissions similar to those reflected in the federal framework. NSPI is engaged with federal and provincial agencies in reviewing the implications of this federal framework and its alignment with its current operating plans under existing Nova Scotia regulations.

Deferral of Certain Tax Benefits Decision

In December 2010, the UARB granted NSPI approval to defer $14.5 million of tax benefits which arose in 2010 related to renewable energy projects. On July 21, 2011, the UARB approved an agreement NSPI reached with stakeholders to apply the deferral against the FAM regulatory asset, which reduced the FAM regulatory asset effective January 1, 2011. The application of the deferral reduced the amount of the FAM balance outstanding with the reduction applied to the amount that would otherwise be recovered from customers in 2012 as noted in the "UARB Decision on 2012 Fuel Adjustment Mechanism" section above.

Light–emitting Diode Streetlight Legislation

On May 19, 2011, the Nova Scotia Government passed legislation making light-emitting diode ("LED") lighting mandatory on Nova Scotia's roads and highways. This legislation builds on previous initiatives focused on energy efficiency and environmental responsibility. The cost to convert to LED lighting province-wide is estimated to be in the range of $100 million. NSPI's related capital costs will be subject to UARB review and approval.

Nova Scotia Provincial Environmental Regulations

On May 19, 2011, the Nova Scotia Government approved The Electricity Act (Amended) to facilitate the eligibility of energy from the Lower Churchill Project in Labrador as a resource for meeting Nova Scotia's renewable electricity targets. The amendment requires regulations to be developed that increase the percentage of renewable energy in the generation mix from the planned 25 percent in 2015, to 40 percent by 2020.

On April 11, 2011, the Nova Scotia Government announced that the cap on the annual amount of new forest biomass that can be used to generate electricity will be lowered by 30 percent to 350,000 dry tonnes per year. NSPI's 60 MW Port Hawkesbury Biomass Project is unaffected by this announcement.

Depreciation Settlement

On May 11, 2011, the UARB approved changes to NSPI's depreciation rates following NSPI's completion of a depreciation study and a settlement agreement with stakeholders. The overall impact on the average depreciation rate is immaterial. The new depreciation rates are effective January 1, 2012, as approved by the UARB in the 2012 General Rate Decision.

Digby Wind Renewable Energy Project

On March 9, 2011, the UARB approved a capital work order for the Digby Wind Renewable Energy Project, which included a substation, network upgrades and interconnection costs, in the amount of $79.8 million. This project went into service in December 2010.

Maine Utility Operations

Private Placement of Senior Unsecured Notes

On January 31, 2012, Bangor Hydro completed the issue of an unsecured $70.0 million USD senior note. The Series 2012-A Senior Note bears interest at a rate of 3.61 percent per annum until January 31, 2022. The net proceeds of the note offering were used to repay borrowings under the revolving credit facility.

Caribbean Utility Operations

Sale of St. Lucia Electricity Services

On January 31, 2012, a wholly-owned subsidiary of Emera sold its 19.1 percent interest in St. Lucia Electricity Services ("Lucelec") at book value to Light & Power Holdings Ltd. ("LPH"), a subsidiary owned 80.1 percent by Emera, for $29.1 million USD effective January 1, 2012. The transaction is expected to allow for greater cooperation between the two electric utilities, including a sharing of skills and increased efficiencies that are expected to result in benefits to customers in both countries. The terms of the acquisition agreement provide for a potential sales price increase or decrease of up to $4 million USD within 30 months of the closing date of the transaction. Any adjustment would be triggered by either an additional public offering by Lucelec or a change in Lucelec's allowed return on equity as a result of a change in its regulatory framework.

GBPC Credit Agreement

On January 25, 2012, GBPC entered into an unsecured credit agreement with Scotiabank (Bahamas) Limited in the amount of $56.2 million USD. The proceeds of the credit agreement will be used to finance the construction of a 52-MW power plant on Grand Bahama Island. The credit agreement bears interest at a rate of the three month LIBOR rate plus 1.2 percent and is repayable in forty equal, consecutive quarterly installments over a ten year period. The payments commence at the earlier of six months after the completion of the construction of the power plant or January 31, 2013.

Appointments

Directors

Ray Ivany, President and Vice-Chancellor of Acadia University, joined NSPI's Board of Directors on September 22, 2011.

James Eisenhauer, FCA was appointed Chairman of NSPI's Board of Directors on May 2, 2011, replacing George A Caines, QC, who retired. On May 4, 2011, Mr. Eisenhauer was elected to Emera's Board of Directors at the Company's Annual General Meeting.

Executive

Bruce Marchand was appointed Chief Legal Officer of Emera Incorporated effective January 1, 2012. Prior to joining Emera, Mr. Marchand was Senior Partner in the Halifax office of McInnes Cooper, an Atlantic Canadian law firm.

Barbara Meens Thistle was appointed Chief Human Resources Officer at Emera Incorporated and Vice President, Human Resources, NSPI on November 25, 2011. Previously, she served as General Manager Human Resources, Procurement and Real Estate at NSPI.

Robert Hanf was appointed Executive Chairman of Light & Power Holdings Ltd. and Director of Barbados Light & Power Company Limited on September 13, 2011. Prior to these appointments, Mr. Hanf served as Chief Legal Officer of Emera Incorporated.

Sarah MacDonald was appointed President and Chief Executive Officer of GBPC on June 7, 2011. Prior to this appointment, Ms. MacDonald served as the Executive Vice President of Human Resources at Emera Incorporated and Chief Executive Officer of Emera Utility Services Inc.

Judy Steele, FCA was appointed Chief Financial Officer of Emera Incorporated on May 16, 2011, on an interim basis until such time as a permanent CFO is named. Prior to this appointment, Ms. Steele served as Vice President Finance of Emera Energy Inc.

Significant Items

Bear Swamp Mark-to-Market Adjustment

As part of its long-term energy and capacity supply agreement with the Long Island Power Authority ("LIPA"), which extends to 2021, Bear Swamp has contracted with Emera's joint venture partner to provide the off-peak power necessary to produce the requirements of the LIPA contract. One of the contracts is marked-to-market through income, as it does not meet the stringent accounting requirements of hedge accounting.

As at December 31, 2011, the fair value of the contract was a net liability of $9.6 million (December 31, 2010 (adjusted) – $8.2 million net liability), which will reverse over the life of the agreement as it is realized.

The mark-to-market adjustment relating to this contract was as follows:

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Mark-to-market (loss) gain	**$(1.2)**	$(4.4)	**$(1.3)**	$(14.4)	$1.2
After-tax mark-to-market (loss) gain	**$(0.7)**	$(2.6)	**$(0.8)**	$(8.6)	$0.7
Earnings per common share – basic	**$0.38**	$0.21	**$1.99**	$1.67	$1.65
Earnings per common share – basic, absent the Bear Swamp after-tax mark-to-market adjustment	**$0.39**	$0.23	**$2.00**	$1.75	$1.64

Gain on Exchange of Subscription Receipts to Shares

As discussed in the Emera Developments section, pursuant to an April 2009 subscription receipts agreement with APUC, and upon closing of the California Pacific transaction in Q1 2011, Emera exchanged subscription receipts acquired in 2009 into 8.523 million APUC common shares, issued at $3.25 per share. This resulted in an after-tax gain of $12.8 million recorded in Q1 2011 in "Other income (expenses), net" on Emera's Consolidated Statements of Income.

Gain on Business Acquisition

Under USGAAP, in circumstances where the fair value of net assets acquired in a business acquisition exceeds the purchase price, the difference is recorded as a gain in the period.

Emera's interest in LPH was acquired in two tranches, in Q2 2010 and Q1 2011, and gave rise to non-taxable gains of $22.5 million and $28.2 million, respectively. These amounts have been recorded in "Other income (expenses), net" on Emera's Consolidated Statements of Income.

REVIEW OF 2011
Emera Consolidated Statements of Income

For the millions of dollars (except earnings per common share)	Three months ended December 31		Year ended December 31		
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Operating revenues	**$512.0**	$408.9	**$2,064.4**	$1,606.1	$1,490.1
Regulated fuel for generation and purchased power	**215.0**	157.8	**866.4**	634.6	550.0
Regulated fuel adjustment	**(4.5)**	(24.0)	**(8.5)**	(99.0)	8.5
Non-regulated fuel for generation and purchased power	**18.3**	19.4	**73.9**	83.9	29.5
Non-regulated direct costs	**20.4**	16.2	**60.9**	62.3	37.9
Operating, maintenance and general	**121.9**	103.7	**455.0**	351.2	299.1
Provincial, state, and municipal taxes	**12.5**	11.9	**49.2**	47.4	48.0
Depreciation and amortization	**73.7**	69.8	**250.0**	213.5	199.7
Income from operations	**54.7**	54.1	**317.5**	312.2	317.4
Income from equity investments	**4.2**	1.7	**21.5**	15.3	28.9
Other income (expenses), net	**1.5**	(5.5)	**43.1**	12.5	20.4
Interest expense, net	**37.3**	37.3	**159.4**	148.8	132.8
Income before provision for income taxes	**23.1**	13.0	**222.7**	191.2	233.9
Income tax expense (recovery)	**(26.3)**	(10.6)	**(36.7)**	(8.1)	37.4
Net income	**49.4**	23.6	**259.4**	199.3	196.5
Non-controlling interest in subsidiaries	**2.6**	(0.5)	**11.7**	5.6	10.2
Net income of Emera Incorporated	**46.8**	24.1	**247.7**	193.7	186.3
Preferred stock dividends	**-**	-	**6.6**	3.0	-
Net income attributable to common shareholders	**$46.8**	$24.1	**$241.1**	$190.7	$186.3
Earnings per common share – basic	**$0.38**	$0.21	**$1.99**	$1.67	$1.65
Earnings per common share – diluted	**$0.38**	$0.21	**$1.97**	$1.65	$1.61

Emera Incorporated’s consolidated net income increased $22.7 million to $46.8 million in Q4 2011 compared to $24.1 million in Q4 2010 (adjusted). For the year ended December 31, 2011, Emera’s consolidated net income increased $50.4 million to $241.1 million compared to $190.7 million in 2010 (adjusted) and $186.3 million in 2009 (adjusted).

Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Consolidated net income attributable to common shareholders – 2009 (adjusted)		**$186.3**
Operating revenues – Increased primarily due to the acquisition of Bayside Power, Brunswick Pipeline becoming operational, and increased EUS revenues due to increase in large construction projects; partially offset by lower fuel-related revenues in NSPI		116.0
Regulated fuel for generation and purchased power – Increased primarily due to higher commodity prices		(84.6)
Regulated fuel adjustment – Increased due to an under-recovery of current year fuel costs and a rebate to customer of prior years' over recovery		107.5
Non-regulated fuel for generation and purchased power – Increased primarily due to the acquisition of Bayside Power		(54.4)
Non-regulated direct costs – Increased primarily due to an increase in large construction projects in EUS		(24.4)
OM&G – Increased primarily due to increased pension, storm and customer service costs and acquisition of Bayside Power		(52.1)
Depreciation and amortization – Increased primarily due to increased property, plant and equipment and increased regulatory amortization		(13.8)
Income from equity investments – Decreased primarily due to unfavourable change in the fair value of the net derivatives in Bear Swamp		(13.6)
Interest expense, net – Increased primarily due to increased debt used to fund business acquisitions		(16.0)
Income tax expense – Decreased primarily due to lower income before provision for income taxes, deductions related to renewable investments and a change in the expected benefit from other accelerated tax deductions		45.5
Other		(5.7)
Consolidated net income attributable to common shareholders – 2010 (adjusted)	**$24.1**	**$190.7**
Operating revenues – Decreased during the quarter primarily due to lower industrial sales volumes in NSPI; increased year-over-year due to higher fuel-related revenues in NSPI	(14.4)	17.4
Regulated fuel for generation and purchased power – Decreased during the quarter primarily due to lower sales volumes; decreased year-over-year primarily due to lower commodity prices and a change in the generation mix	16.2	41.8
Regulated fuel adjustment – Decreased due to an under-recovery of current period fuel costs and change in recovery of prior periods' FAM balance	(19.5)	(90.5)
Income tax expense – Decreased primarily due to a change in the expected benefit from accelerated tax deductions and lower income before provision for income taxes in NSPI	16.7	31.2
Impact of the acquisitions of GBPC, MAM and LPH	3.8	47.7
Other	19.9	2.8
Consolidated net income attributable to common shareholders – 2011	**$46.8**	**$241.1**

Consolidated Balance Sheets Highlights

Significant changes in the consolidated balance sheets between December 31, 2011 and 2010 (adjusted) include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Cash and cash equivalents	**$69.6**	See consolidated cash flow highlights section.
Restricted cash	**(44.6)**	Decreased primarily due to use of restricted cash in Q1 2011 in connection with the CPUV investment, partially offset by restricted cash acquired with LPH acquisition[1].
Receivables, net	**66.7**	Increased primarily due to acquisition of a controlling interest in LPH [1], higher fuel-related electricity pricing effective January 1, 2011 and timing of billings and receipts.
Inventory	**21.0**	Increased primarily due to acquisition of a controlling interest in LPH [1].
Derivative instruments (current and long-term)	**(18.8)**	Decreased primarily due to settlements and unfavourable commodity positions, partially offset by favourable USD price positions.
Other assets (current and long-term)	**114.7**	Increased primarily due to purchases of APUC subscription receipts.
Property, plant & equipment, net of accumulated depreciation	**551.8**	Increased primarily due to acquisition of a controlling interest in LPH [1] and capital spending, partially offset by depreciation.
Investments subject to significant influence	**(23.3)**	Decreased primarily due to acquisition of a controlling interest in LPH [1], partially offset by the APUC investment.
Available-for-sale investments	**53.8**	Increased due to acquisition of a controlling interest in LPH [1].
Goodwill	**30.3**	Increased primarily due to finalization of purchase price allocation of GBPC and a weaker Canadian dollar.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**311.9**	Increased primarily due to acquisition of a controlling interest in LPH [1] and purchases of APUC subscription receipts.
Accounts payable	**39.0**	Increased due to timing of payments and acquisition of a controlling interest in LPH [1].
Deferred income taxes (current and long-term)	**62.5**	Increased primarily due to increased deferred income tax liability on property, plant and equipment, including renewable investments and acquisition of a controlling interest in LPH [1], resulting in reclassification of a deferred income tax asset.
Regulatory liabilities (current and long-term)	**10.8**	Increased primarily due to acquisition of a controlling interest in LPH [1], partially offset by decreased deferred income tax regulatory liability, decreased derivative regulatory liability and decreased regulatory liability related to the 2010 renewable tax benefits deferral.
Pension and post-retirement liabilities (current and long-term)	**130.7**	Increased primarily due to a change in the discount rate used in determining the pension and post-retirement obligations, and 2011 investment losses.
Other liabilities (current and long- term)	**14.5**	Increased primarily due to acquisition of a controlling interest in LPH [1].
Asset retirement obligations	**(41.9)**	Decreased primarily due to change in estimates of retirement dates and future decommissioning costs, partially offset by acquisition of a controlling interest in LPH [1].
Common stock	**247.2**	Issuance of common shares.
Accumulated other comprehensive loss	**107.5**	Increased primarily due to higher underfunded amount in pension plans resulting from a change in discount rates, and 2011 investments losses; partially offset by the favourable effect of a stronger CAD on Emera's foreign subsidiaries.
Retained earnings	**82.4**	Net income of Emera in excess of dividends paid.
Non-controlling interest in subsidiaries	**70.1**	Increased primarily due to acquisition of a controlling interest in LPH [1].

(1) Emera acquired a controlling interest in LPH in 2011, and accordingly, its asset and liabilities are fully consolidated in the December 31, 2011 Balance Sheets. Previously, LPH had been accounted for under the equity method, with the net investments included in "Investments Subject to Significant Influence".

Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between December 31, 2011 and 2010 (adjusted) include:

Year ended December 31 millions of Canadian dollars	**2011**	2010 (adjusted)	Explanation
Cash and cash equivalents, beginning of period	**$7.3**	$20.2	
Provided by (used in):			
Operating activities	**399.5**	419.2	Cash provided by operating activities decreased in 2011 primarily due to unfavourable non-cash working capital changes. Cash from operating activities excluding non-cash working capital increased primarily due to the collection of the FAM receivable and the acquisitions of LPH, GBPC and MAM.
Investing activities	**(660.8)**	(886.0)	Cash used in investing activities decreased in 2011 primarily due to the acquisitions of MPS and GBPC in 2010, and lower capital spending in NSPI; partially offset by the purchase of CPUV, and APUC subscription receipts.
Financing activities	**331.4**	454.6	Cash provided by financing activities decreased in 2011 primarily due to reduced borrowing and higher dividends on common and preferred shares, partially offset by a common share issuance.
Foreign currency impact on cash balances	**(0.5)**	(0.7)	
Cash and cash equivalents, end of period	**$76.9**	$7.3	

Outstanding Share Data

Issued and Outstanding:	Millions of Shares	Common Stock millions of Canadian dollars
December 31, 2009 (adjusted)	112.98	$1,097.9
Issued for cash under Purchase Plans	1.32	34.4
Discount on shares purchased under Dividend Reinvestment Plan	-	(1.5)
Options exercised under senior management stock option plan	0.32	6.0
Stock-based compensation	-	1.0
December 31, 2010 (adjusted)	114.62	$1,137.8
Issuance of common stock	6.36	196.0
Issued for cash under Purchase Plans	1.40	42.8
Discount on shares purchased under Dividend Reinvestment Plan	-	(1.8)
Options exercised under senior management stock option plan	0.45	8.8
Stock-based compensation	-	1.4
December 31, 2011	**122.83**	**$1,385.0**

As at January 27, 2012, the amount of issued and outstanding common stock was 122.95 million.

NSPI

Overview

NSPI was created in 1992 through the privatization of the crown corporation Nova Scotia Power Corporation ("NSPC"). NSPI is a fully-integrated regulated electric utility and the primary electricity supplier in Nova Scotia. NSPI has $3.9 billion of assets and provides electricity generation, transmission and distribution services to approximately 493,000 customers. The Company owns 2,374 MW of generating capacity, of which approximately 52 percent is coal-fired; natural gas and/or oil comprise another 28 percent of capacity; and hydro and wind total 20 percent. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP"). These IPPs own 229 MW, increasing to 259 MW in 2012, of wind and biomass fueled generation capacity. A further 83 MW of renewable capacity is being built directly or purchased under long-term contracts by NSPI and is expected to be in service by the end of 2013. NSPI also owns approximately 5,000 kilometers of transmission facilities and 26,000 kilometers of distribution facilities. The Company has a workforce of approximately 1,900 people.

NSPI is a public utility as defined in the Public Utilities Act (Nova Scotia) ("Act") and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. The Company is not subject to a general annual rate review process, but rather participates in hearings from time to time at the Company's or the UARB's request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's target regulated return on equity ("ROE") range for 2011 was 9.1 percent to 9.6 percent, based on an actual, average regulated common equity component of up to 40 percent of regulated capitalization. The 2012 General Rate Decision adjusted the 2012 ROE range to 9.1 percent to 9.5 percent.

On May 13, 2011, NSPI filed a GRA with the UARB requesting an average 7.3 percent rate increase across all customer classes effective January 1, 2012. On November 29, 2011, the UARB approved the settlement which resulted in an average rate increase of approximately 5.1 percent for all customers, effective January 1, 2012. Rates were approved based on a 9.2 percent ROE, applied to a 37.5 percent common equity component.

In 2009, the UARB approved a FAM allowing NSPI to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

Review of 2011

NSPI Net Income millions of Canadian dollars (except per share amounts)	Three months ended December 31			Year ended December 31	
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Operating revenues	**$289.2**	$303.2	**$1,233.0**	$1,191.4	$1,211.8
Fuel for generation and purchased power	**127.0**	146.1	**546.3**	578.6	525.8
Fuel for generation and purchased power – affiliates (1)	**0.8**	0.1	**1.1**	8.1	(25.1)
Fuel adjustment	**(4.5)**	(24.0)	**(8.5)**	(99.0)	8.5
Operating, maintenance and general	**75.0**	67.5	**268.6**	245.8	223.9
Provincial grants and taxes	**9.8**	10.1	**38.7**	40.1	40.5
Depreciation and amortization	**58.8**	63.7	**187.2**	188.1	171.5
Total operating expenses	**266.9**	263.5	**1,033.4**	961.7	945.1
Income from operations	**22.3**	39.7	**199.6**	229.7	266.7
Other expenses, net	**2.1**	3.5	**8.9**	11.3	3.3
Interest expense, net	**23.6**	26.8	**104.2**	104.7	102.8
Income before provision for income taxes	**(3.4)**	9.4	**86.5**	113.7	160.6
Income tax (recovery) expense	**(27.5)**	(12.4)	**(44.9)**	(13.4)	40.3
Net income of Nova Scotia Power Inc.	**24.1**	21.8	**131.4**	127.1	120.3
Preferred stock dividends	**1.9**	1.9	**7.9**	7.9	9.5
Contribution to consolidated net income	**$22.2**	$19.9	**$123.5**	$119.2	$110.8
Contribution to consolidated earnings per common share	**$0.18**	$0.17	**$1.02**	$1.04	$0.98

(1) Fuel for generation and purchased power – affiliates includes proceeds from the sale of natural gas.

NSPI's contribution to consolidated net income increased $2.3 million to $22.2 million in Q4 2011 compared to $19.9 million in Q4 2010 (adjusted). NSPI's contribution to consolidated net income for the year ended December 31, 2011 increased $4.3 million to $123.5 million compared to $119.2 million in 2010 (adjusted) and $110.8 million in 2009 (adjusted). Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2009 (adjusted)		**$110.8**
Decreased electric margin (see Electric Margin section for explanation)		(11.6)
Increased OM&G expenses primarily due to increased pension, storm costs and customer service initiatives		(21.9)
Increased net depreciation and amortization primarily due to increased property, plant and equipment and increased regulatory amortization		(16.1)
Decreased other expenses, net primarily due to increased allowance for equity funds used during construction related to increased capital spending		4.3
Decreased income taxes primarily due to decreased income before provision for income taxes, deductions related to renewable investments and a change in the expected benefit from other accelerated tax deductions		53.7
Contribution to consolidated net income – 2010 (adjusted)	**$19.9**	**$119.2**
Decreased electric margin (see Electric Margin section for explanation)	(12.6)	(6.9)
Increased OM&G expenses primarily due to increased pension costs, plant maintenance costs and labour escalation	(7.5)	(22.8)
Decreased net depreciation and amortization primarily due to decreased regulatory amortization partially offset by increased property, plant and equipment	4.7	1.7
Increased income tax recovery primarily due to a change in the expected benefit from accelerated tax deductions and decreased income before provision for income taxes	15.1	31.5
Other	2.6	0.8
Contribution to consolidated net income – 2011	**$22.2**	**$123.5**

Operating Revenues – Regulated

NSPI's Operating Revenues – Regulated include sales of electricity and other services as summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31				Year ended December 31
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Electric revenues	**$282.9**	$296.4	**$1,209.7**	$1,167.3	$1,188.1
Other revenues	**6.3**	6.8	**23.3**	24.1	23.7
Operating revenues – regulated	**$289.2**	$303.2	**$1,233.0**	$1,191.4	$1,211.8

Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal, with Q1 and Q4 the strongest periods, reflecting colder weather and fewer daylight hours in the winter season.

NSPI's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, and the province's universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other electric revenues consist of export sales, sales to municipal electric utilities and revenues from street lighting.

Electric sales volumes are summarized in the following tables by customer class:

Q4 Electric Sales Volumes
Gigawatt hours ("GWh")

	2011	2010	2009
Residential	**1,073**	1,080	1,091
Commercial	**768**	765	772
Industrial	**568**	957	998
Other	**83**	84	81
Total	**2,492**	2,886	2,942

Annual Electric Sales Volumes
GWh

	2011	2010	2009
Residential	**4,275**	4,147	4,228
Commercial	**3,102**	3,088	3,107
Industrial	**3,516**	3,908	3,642
Other	**313**	312	328
Total	**11,206**	11,455	11,305

Electric revenues are summarized in the following tables by customer class:

Q4 Electric Revenues
millions of Canadian dollars

	2011	2010	2009
Residential	**$141.0**	$137.1	$140.4
Commercial	**85.8**	82.2	84.2
Industrial	**45.2**	66.0	67.3
Other	**10.9**	11.1	11.0
Total	**$282.9**	$296.4	$302.9

Annual Electric Revenues
millions of Canadian dollars

	2011	2010	2009
Residential	**$564.9**	$531.0	$547.3
Commercial	**341.8**	325.4	333.9
Industrial	**260.1**	269.3	263.8
Other	**42.9**	41.6	43.1
Total	**$1,209.7**	$1,167.3	$1,188.1

Electric revenues decreased $13.5 million to $282.9 million in Q4 2011 compared to $296.4 million in Q4 2010. For the year ended December 31, 2011, electric revenues increased $42.4 million to $1,209.7 million compared to $1,167.3 million in 2010 and $1,188.1 million in 2009. Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Electric revenues – 2009		**$1,188.1**
Decreased fuel-related electricity pricing effective January 1, 2010		(22.4)
Change in residential and commercial sales volumes primarily due to warmer weather		(10.7)
Increased industrial sales volumes from several large industrial customers		13.2
Other		(0.9)
Electric revenues – 2010	**$296.4**	**$1,167.3**
Increased fuel-related electricity pricing effective January 1, 2011	11.5	51.5
Year-over-year increased residential sales volumes due to load growth and colder weather	(1.2)	15.2
Decreased industrial sales volume primarily due to suspended operations of a large industrial customer	(23.2)	(24.1)
Other	(0.6)	(0.2)
Electric revenues – 2011	**$282.9**	**$1,209.7**

Electric Margin

NSPI distinguishes revenues related to the recovery of fuel costs (“fuel electric revenues”) from revenues related to the recovery of non-fuel costs (“non-fuel electric revenues”) because the FAM introduced on January 1, 2009 enables NSPI to seek recovery of fuel costs through regularly scheduled rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year. Consequently, fuel electric revenues and fuel costs do not have a material effect on NSPI’s electric margin or net income, with the exception of the incentive component of the FAM, whereby NSPI retains or absorbs 10 percent of the over or under recovered amount to a maximum of $5 million.

As fuel costs are recovered through the FAM, electric margin and net income are influenced primarily by revenues relating to non-fuel costs. NSPI’s customer classes contribute differently to the Company’s non-fuel electric revenues, with residential and commercial customers contributing more than industrials. Accordingly, changes in residential and commercial load, largely due to weather and growth, have the largest effect on non-fuel electric revenues. Changes in industrial load, which are generally due to economic conditions, have less of an effect on non-fuel electric revenues than a similar volume change in residential and commercial load.

Electric margin is summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
	2011	2010	**2011**	2010	2009
Fuel electric revenues – current year	**$115.6**	$129.1	**$512.6**	$513.7	$509.3
Fuel electric revenues – preceding years	**6.1**	(5.7)	**26.6**	(22.4)	-
Non-fuel electric revenues	**161.2**	173.0	**670.5**	676.0	678.8
Total electric revenues	**$282.9**	$296.4	**$1,209.7**	$1,167.3	$1,188.1
Fuel for generation and purchased power, including affiliates	**(127.8)**	(146.2)	**(547.4)**	(586.7)	(500.7)
Fuel adjustment	**4.5**	24.0	**8.5**	99.0	(8.5)
Foreign exchange and other fuel-related costs	**(1.4)**	(3.4)	**(7.4)**	(9.3)	3.0
Electric margin	**$158.2**	$170.8	**$663.4**	$670.3	$681.9

NSPI's electric margin decreased $12.6 million to $158.2 million in Q4 2011 compared to $170.8 million in Q4 2010 primarily due to decreased large industrial sales. For the year ended December 31, 2011, NSPI's electric margin decreased $6.9 million to $663.4 million compared to $670.3 million in 2010 primarily due to decreased large industrial sales, partially offset by increased residential sales as a result of load growth and colder weather. NSPI's electric margin decreased in 2010 to $670.3 million from $681.9 million in 2009 due to lower residential sales related to warmer weather and the recognition of a FAM incentive expense compared to a recovery in 2009.

Q4 Average Electric Margin/Megawatt hour ("MWh")

	2011	2010	2009
Dollars per MWh	$63	$59	$59

Annual Average Electric Margin/MWh

	2011	2010	2009
Dollars per MWh	$59	$59	$60

The change in average electric margin per MWh in Q4 2011 compared to Q4 2010 reflects a change in sales volume mix largely due to decreased large industrial sales.

The change in average electric margin per MWh in 2010 compared to 2009 reflects a change in sales volume mix and recognition of a FAM incentive expense in 2010 compared to a recovery in 2009.

Regulated Fuel for Generation and Purchased Power (including affiliates)

Capacity

To ensure reliability of service, NSPI maintains a generating capacity greater than firm peak demand. The total Company-owned generation capacity is 2,374 MW, which is supplemented by 229 MW contracted with IPPs. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area and the Northeast Power Coordinating Council.

NSPI facilities continue to rank among the best in Canada on capacity related performance indicators. The high availability and capability of low cost thermal generating stations provide lower cost energy to customers. In 2011, thermal plant availability was unchanged from 2010 at 87 percent. Sustained high availability and low forced outage rates on low cost facilities are good indicators of sound maintenance and investment practices.

Q4 Production Volumes
GWh

	2011	2010	2009
Coal and petcoke	**1,624**	2,049	2,069
Natural gas	**482**	438	534
Oil	**7**	16	16
Renewables	**327**	340	281
Purchased power	**298**	315	335
Total	**2,738**	3,158	3,235

Purchased power includes 227 GWh of renewables in Q4 2011 (2010 – 175 GWh; 2009 – 92 GWh).

Annual Production Volumes
GWh

	2011	2010	2009
Coal and petcoke	**6,848**	7,839	8,177
Natural gas	**2,430**	2,275	1,612
Oil	**35**	36	307
Renewables	**1,335**	1,017	1,065
Purchased power	**1,269**	997	931
Total	**11,917**	12,164	12,092

Purchased power includes 743 GWh of renewables in 2011 (2010 – 526 GWh; 2009 – 301 GWh).

Q4 Average Unit Fuel Costs

	2011	2010	2009
Dollars per MWh	**$47**	$46	$43

Annual Average Unit Fuel Costs

	2011	2010	2009
Dollars per MWh	**$46**	$48	$41

NSPI's percentage of solid fuel generation decreased to approximately 57 percent in 2011, down from 64 percent in 2010 and 68 percent in 2009. Economic dispatch of the generating fleet brings the lowest cost options on stream first, such that the incremental cost of production increases as sales volume increases. Historically, solid fuels have had the lowest per unit fuel cost, after hydro and NSPI-owned wind, which have no fuel cost component. Natural gas, oil, and purchased power have the next lowest fuel cost, depending on the relative pricing of each. During 2011, natural gas represented a higher percentage of the annual energy requirement than prior years as economic dispatch favored natural gas for much of the year. Additionally, the introduction of new renewable generation has decreased coal consumption.

The average unit fuel costs decreased in 2011 compared to 2010 primarily due to decreased natural gas prices and increased hydro and wind production.

The average unit fuel costs increased in 2010 compared to 2009 primarily due to higher priced imported coal and solid fuel commodity mix related to emission compliance.

A large portion of NSPI's fuel supply comes from international suppliers, and is subject to commodity price and foreign exchange risk. NSPI seeks to manage this risk through the use of financial hedging instruments and physical contracts and utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. Foreign exchange risk is managed through forward and swap contracts. Fuel contracts may also be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. Further details on NSPI's risk management strategies related to fuel for generation and purchased power are discussed in the Business Risks section.

Fuel for generation and purchased power, including affiliates decreased $18.4 million to $127.8 million in Q4 2011 compared to $146.2 million in Q4 2010. For the year ended December 31, 2011, fuel for generation and purchased power, including affiliates decreased $39.3 million to $547.4 million compared to $586.7 million in 2010 and $500.7 million in 2009.

Highlights of the changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Fuel for generation and purchased power, including affiliates – 2009		**$500.7**
Commodity price and volume increases		34.5
Changes in generation mix and plant performance		24.3
Solid fuel commodity mix and additives related to emission compliance		25.3
Valuation of contract receivable (see discussion below)		8.7
Increased sales volume		2.7
Increased hydro production		(1.1)
Increased proceeds from the resale of natural gas		(9.8)
Mark-to-market on natural gas hedges recognized in 2009 as they were no longer required due to decreased 2009 production volumes		2.2
Other		(0.8)
Fuel for generation and purchased power, including affiliates – 2010	**$146.2**	**$586.7**
Valuation of contract receivable (see discussion below)	3.2	27.8
Changes in generation mix and plant performance	(3.9)	12.0
Decreased commodity prices	(1.0)	(38.9)
Decreased (increased) hydro and wind production	0.6	(19.9)
Changes in solid fuel commodity mix and additives related to emission compliance	3.2	(7.3)
Decreased sales volume	(18.8)	(8.3)
Other	(1.7)	(4.7)
Fuel for generation and purchased power, including affiliates – 2011	**$127.8**	**$547.4**

NSPI had a long-term contract receivable with a natural gas supplier that was required to be fair-valued. The natural gas supply contract settled in November 2010. The fair value related to the contract had a favourable impact on natural gas pricing during 2010. The effect is segregated in the table above.

Regulated Fuel Adjustment

The regulated fuel adjustment related to the fuel adjustment mechanism ("FAM") for NSPI includes the effect of fuel costs in both the current and two preceding years specifically:

- The difference between actual fuel costs and amounts recovered from customers in the current year. This amount, net of the incentive component, is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities".
- The recovery from (rebate to) customers of under (over) recovered fuel costs from prior years.

On December 19, 2011, the UARB approved NSPI's customer rates associated with the 2012 FAM adjustment related to the recovery of prior period fuel costs. The recovery of these costs began January 1, 2012. The approved customer rates seek to recover $69.0 million of prior years' unrecovered fuel costs in 2012.

In December 2010, as part of the FAM regulatory process, the UARB approved NSPI's setting of the 2011 base cost of fuel and the under-recovered fuel-related costs from prior years. The UARB approved the recovery of the prior year FAM balance from customers over three years, effective January 1, 2011, with 50 percent to be recovered in 2011, 30 percent in 2012 and 20 percent in 2013.

Details of the FAM regulatory asset are summarized in the following table:

millions of Canadian dollars	**2011**	2010	2009
FAM regulatory asset (liability) – Balance at January 1	**$92.9**	$(9.9)	-
Under (over) recovery of current year fuel costs	**35.1**	76.6	$(8.5)
(Recovery from) rebate to customers of prior years' fuel costs	**(26.6)**	22.4	-
Application of deferral related to tax benefits from 2010	**(14.5)**	-	-
Interest revenue (expense) on FAM balance	**6.8**	3.8	(1.4)
FAM regulatory asset (liability) – Balance at December 31	**$93.7**	$92.9	$(9.9)

NSPI has recognized a deferred income tax expense related to the fuel adjustment based on NSPI's enacted statutory income tax rate. As at December 31, 2011, NSPI's deferred income tax liability related to the FAM was $29.0 million (2010 – $29.2 million).

Provincial Grants and Taxes

NSPI pays annual grants to the Province of Nova Scotia in lieu of municipal taxation other than deed transfer tax.

Regulatory Amortization

Regulatory amortization is included in depreciation and amortization. Regulatory amortization decreased $7.7 million to $16.0 in Q4 2011 compared to $23.7 million in Q4 2010 and decreased $17.8 million to $19.1 million for the year ended December 31, 2011 compared to $36.9 million in 2010 primarily due to a $14.5 million deferral of certain tax benefits arising in 2010 related to renewable energy projects and decreased discretionary regulatory amortization recorded in 2011, as discussed below.

Regulatory amortization increased $9.7 million to $36.9 million for the year ended December 31, 2010 compared to $27.2 million in 2009 primarily due to a $14.5 million deferral of certain tax benefits arising in 2010 related to renewable energy projects as approved by the UARB, partially offset by a reduction in amortization of the pre-2003 income tax regulatory asset resulting from the UARB's 2010 ROE decision of $4.8 million in 2010 (2009 – $10.0 million). The 2010 ROE decision allows NSPI to recognize additional amortization amounts in current periods and to reduce amortization in future periods to provide flexibility relating to customer rate requirements.

Other Expenses, Net

Other expenses, net decreased $1.4 million to $2.1 million in Q4 2011 compared to $3.5 million in Q4 2010 (adjusted) and decreased $2.4 million to $8.9 million for the year ended December 31, 2011 compared to $11.3 million in 2010 (adjusted) primarily due to decreased foreign exchange losses recovered through the FAM.

Other expenses, net increased $8.0 million to $11.3 million for the year ended December 31, 2010 (adjusted) compared to $3.3 million in 2009 (adjusted) primarily due to increased foreign exchange losses, recovered through the FAM, partially offset by increased allowance for equity funds used during construction related to increased capital spending.

Income Taxes

In 2011, NSPI was subject to provincial capital tax (0.075 percent), corporate income tax (32.5 percent) and Part VI.1 tax relating to preferred stock dividends (40 percent). NSPI also receives a reduction in its corporate income tax otherwise payable related to the Part VI.1 tax deduction (29 percent of preferred stock dividends).

In Q4 2011, NSPI modified its estimate of the expected tax benefit of tax deductions, electing to amend its tax returns for the years 2006 through 2009. This resulted in a $23.3 million reduction in income tax expense and a $3.0 million increase in interest revenue, recorded in the quarter. This change in accounting estimate has been accounted for on a prospective basis.

In Q4 2010, NSPI revised its estimate of the 2010 expected benefit from accelerated tax deductions, resulting in a $7.2 million reduction in income tax expense.

MAINE UTILITY OPERATIONS

Overview

Maine Utility Operations ("Maine Utilities") includes Bangor Hydro Electric Company ("Bangor Hydro"), Maine Public Service Company ("MPS") and Maine and Maritimes Corporation ("MAM"), the parent company of MPS. All amounts in the Maine Utility Operations section are reported in USD unless otherwise stated. MAM was purchased in late December 2010, thus its results are not included in the 2010 (adjusted) or 2009 (adjusted) comparative information.

Bangor Hydro and MPS are both transmission and distribution ("T&D") electric utilities. Bangor Hydro is the second largest electric utility in Maine. Bangor Hydro has approximately $806.8 million of assets and serves approximately 118,000 customers in eastern Maine while MPS has approximately $139.6 million of assets and serves approximately 36,000 customers in northern Maine.

Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the energy delivered through both utilities' T&D networks. Bangor Hydro owns and operates approximately 1,000 kilometers of transmission facilities and 7,200 kilometers of distribution facilities. Bangor Hydro's workforce is approximately 300 people. MPS owns and operates approximately 600 kilometers of transmission facilities, and 2,900 kilometers of distribution facilities. MPS' workforce is approximately 125 people. The Maine Utilities currently have approximately $150 million of additional transmission development in progress.

Approximately 50 percent of Maine Utilities' electric revenue represents distribution operations, 33 percent is associated with transmission operations and 17 percent relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

<u>Distribution Operations</u>

Maine Utilities' distribution businesses operate under a traditional cost-of-service regulatory structure. Distribution rates are set based on an allowed ROE of 10.2 percent, on a common equity component of 50 percent.

<u>Transmission Operations</u>

Bangor Hydro
Bangor Hydro's local transmission rates are set by the FERC annually on June 1, based upon a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted transmission investments and expenses. The allowed ROE for these local transmission investments is 11.14 percent. The common equity component is based upon the prior calendar year actual average balances. On June 1, 2011, Bangor Hydro's local transmission rates decreased by approximately 10 percent (2010 – increased 37 percent).

Bangor Hydro's bulk transmission assets are managed by the ISO-New England ("ISO") as part of a region-wide pool of assets. The ISO manages the regions' bulk power generation and transmission systems and administers the open access transmission tariff. Currently, Bangor Hydro, along with all other participating transmission providers, recovers the full cost of service for its transmission assets from distribution companies in New England, based on a regional formula that is updated on June 1 of each year. This formula is based on prior year regionally funded transmission investments and expenses, adjusted for current year forecasted investments and expenses. Bangor Hydro's allowed ROE for these transmission investments ranges from 11.64 percent to 12.64 percent, and the common equity component is based upon the prior calendar year average balances. The cost recovery is recorded as transmission pool revenue in the Consolidated Statements of Income. The participating transmission providers are also required to contribute to the cost of service of such transmission assets on a ratable basis according to the proportion of the total New England load that their customers represent. These transmission pool expenses are recorded in “Regulated fuel for generation and purchased power” in the Consolidated Statements of Income.

On June 1, 2010, Bangor Hydro’s regional transmission revenue requirement increased by 22 percent, and on June 1, 2011, it increased by a further 9 percent.

MPS
MPS local transmission rates are set annually based on a formula through its Open Access Transmission Tariff (“OATT”). Rates derived from the previous calendar year results go into effect June 1 for wholesale customers and July 1 for retail customers. The allowed ROE for transmission operations is 10.5 percent, and is based on the actual prior calendar year common equity balances. The allowed ROE is determined by negotiation with customers in the formula change years of the OATT, which occur every three years. The last OATT formula change year was 2009. On June 1, 2011, MPS’ local transmission rates increased by 3 percent for wholesale customers (2010 – increased 63 percent) and by 4 percent for retail customers (2010 – increased by 64 percent) on July 1, 2011.

MPS’ electric service territory is not interconnected to the New England bulk power systems, and MPS is not a member of ISO New England.

Stranded Cost Recoveries

Electric utilities in Maine are entitled to recover all prudently incurred stranded costs resulting from the restructuring of the industry in 2000 that could not be mitigated or that arose as a result of rate and accounting orders issued by the MPUC. Unlike T&D operational assets, which are generally sustained with new investment, the net stranded cost regulatory asset pool diminishes over time as elements are amortized through charges to income and recovered through rates. Generally, regulatory rates to recover stranded costs are set every three years, on a levelized basis, and determined under a traditional cost-of-service approach.

Bangor Hydro
Bangor Hydro’s net regulatory assets primarily include the costs associated with the restructuring of an above-market power purchase contract and the unamortized portion on its loss on the sale of its investment in the Seabrook nuclear facility. These net regulatory assets total approximately $65.3 million as at December 31, 2011 (2010 – $74.9 million) or 8 percent of Bangor Hydro’s net asset base (2010 – 10 percent).

In May 2011, the MPUC approved an approximate 27 percent increase in Bangor Hydro’s stranded cost rates for the period of June 1, 2011 to February 28, 2014. The increased stranded cost revenues are offset, for the most part by changes in regulatory amortizations, purchased power expense and resale of purchased power. The allowed ROE used in setting these new stranded cost rates is 7.4 percent, with a common equity component of 48 percent.

While the stranded cost revenue requirements differ throughout the period due to changes in annual stranded costs, the actual annual stranded cost revenues are the same during the period. To levelize the impact of the varying revenue requirements, cost or revenue deferrals are recorded as a regulatory asset or liability, and addressed in subsequent stranded cost rate proceedings, where customer rates are adjusted accordingly.

MPS
In December 2011, the MPUC approved MPS’ stranded cost rates for the three-year period January 1, 2012 through December 31, 2014. This revised three-year agreement, which amortizes essentially all of MPS’ remaining stranded costs, has an ROE of 7.2 percent and a common equity component of 50 percent. Any residual stranded costs remaining after December 31, 2014 will be recovered in future rate proceedings.

Review of 2011

Maine Utilities' Net Income millions of US dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Operating revenues – regulated	**$50.6**	$42.8	**$204.1**	$167.2	$151.5
Operating revenues – non-regulated	**0.1**	-	**0.5**	-	-
Total operating revenues	**50.7**	42.8	**204.6**	167.2	151.5
Regulated fuel for generation and purchased power	**9.2**	7.5	**27.9**	29.2	27.7
Transmission pool expense (1)	**4.3**	4.9	**17.9**	18.3	15.5
Operating, maintenance and general	**10.6**	10.2	**45.3**	36.3	29.6
Provincial, state and municipal taxes	**2.2**	1.6	**9.0**	6.8	6.3
Depreciation and amortization	**8.4**	5.1	**36.9**	20.9	23.5
Total operating expenses	**34.7**	29.3	**137.0**	111.5	102.6
Income from operations	**16.0**	13.5	**67.6**	55.7	48.9
Other income	**1.6**	1.1	**4.3**	4.1	2.3
Interest expense, net	**2.8**	2.7	**11.8**	10.7	12.2
Income before provision for income taxes	**14.8**	11.9	**60.1**	49.1	39.0
Income tax expense	**5.2**	4.3	**22.7**	18.2	13.9
Contribution to consolidated net income – USD	**$9.6**	$7.6	**$37.4**	$30.9	$25.1
Contribution to consolidated net income – CAD	**$9.8**	$7.8	**$37.0**	$31.9	$27.5
Contribution to consolidated earnings per common share – CAD	**$0.08**	$0.07	**$0.31**	$0.28	$0.24
Net income weighted average foreign exchange rate – CAD/USD	**$1.02**	$1.03	**$0.99**	$1.03	$1.10

(1) Transmission pool expense is included in "Regulated fuel for generation and purchased power" on the Consolidated Statements of Income.

Maine Utilities' contribution to consolidated net income increased by $2.0 million to $9.6 million in Q4 2011 compared to $7.6 million in Q4 2010 (adjusted). Maine Utilities' contribution to consolidated net income increased by $6.5 million to $37.4 million for the year ended December 31, 2011 compared to $30.9 million in 2010 (adjusted) and $25.1 million in 2009 (adjusted).

Highlights of the net income changes are summarized in the following table:

For the millions of US dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2009 (adjusted)		**$25.1**
Increased electric revenue due primarily to transmission rate increases in 2009 and 2010		6.1
Increased transmission pool revenue due to recovery of regionally funded transmission investments		10.2
Increased OM&G expenses primarily due to increased labour and benefit costs and lower capitalized construction overheads		(6.7)
Increased transmission pool expenses due to increased charges for Bangor Hydro's share of regionally funded transmission investments and expenses as well as favourable temperatures during high peak electric loads in New England in 2010		(2.8)
Increased income tax expense primarily due to increased income before provision for income taxes		(4.3)
Other		3.3
Contribution to consolidated net income – 2010 (adjusted)	**$7.6**	**$30.9**
Decreased electric revenue during the quarter in Bangor Hydro due to lower sales volumes resulting from warmer temperatures, a transmission rate decrease in June 2011 and lower transmission wheeling revenue from a wind generator	(2.0)	(0.9)
Increased transmission pool revenue year-over-year primarily due to recovery on larger regionally funded transmission investments, partially offset by less favourable weather in 2011	(0.4)	2.2
Decreased OM&G expenses in Bangor Hydro primarily due to an increase in capitalized construction overheads	2.9	3.9
Increased Bangor Hydro income tax expense primarily due to increased income before provision for income taxes	(0.5)	(2.7)
Impact of the acquisition of MAM net of income taxes	1.1	2.7
Other	0.9	1.3
Contribution to consolidated net income – 2011	**$9.6**	**$37.4**

Maine Utilities' USD and CAD contribution to consolidated net income increased in Q4 2011 and for the year ended December 31, 2011. The impact of a stronger Canadian dollar, year over year, reduced CAD earnings by $0.1 million in Q4 2011 and $1.5 million for the year ended December 31, 2011.

For the three months ended December 31, 2011, MPS contributed approximately $9.2 million to Maine Utilities' Operating revenues – regulated and $1.1 million to consolidated net income. For the year ended December 31, 2011, MPS contributed approximately $34.9 million to Maine Utilities' Operating revenues – regulated and $2.7 million to consolidated net income. MPS was purchased in late December 2010, and accordingly did not have an impact on 2010 or 2009 operating revenues – regulated nor consolidated net income.

Operating Revenues – Regulated

Q4 Operating Revenues – Regulated
millions of US dollars

	2011	* 2010 (adjusted)	* 2009 (adjusted)
Residential	**$17.2**	$13.6	$12.6
Commercial	**14.3**	10.3	9.1
Industrial	**2.6**	2.9	2.4
Other	**3.0**	2.2	1.9
Total electric revenues	**$37.1**	$29.0	$26.0
Resale of purchased power	**4.7**	4.6	4.9
Transmission pool	**8.8**	9.2	7.0
Operating revenues – regulated	**$50.6**	$42.8	$37.9

Annual Operating Revenues – Regulated
millions of US dollars

	2011	*2010 (adjusted)	*2009 (adjusted)
Residential	**$68.1**	$50.6	$48.3
Commercial	**56.2**	39.4	35.9
Industrial	**11.2**	11.5	10.2
Other	**10.3**	9.4	10.4
Total electric revenues	**$145.8**	$110.9	$104.8
Resale of purchased power	**18.1**	18.3	18.9
Transmission pool	**40.2**	38.0	27.8
Operating revenues – regulated	**$204.1**	$167.2	$151.5

Electric sales volume is primarily driven by general economic conditions, population and weather. Electric sales pricing in Maine is regulated, and therefore changes in accordance with regulatory decisions.

For the millions of US dollars	Three months ended December 31	Year ended December 31
Operating revenues – regulated 2009		**$151.5**
Increased electric revenues due to increased transmission rates discussed below, increased load offset by a reduction in stranded cost rates		6.1
Increased transmission pool revenues due to recovery of higher regionally-funded transmission investments and more favourable temperatures		10.2
Other		(0.6)
Operating revenues – regulated 2010	**$42.8**	**$167.2**
Increased electric revenues due to acquisition of MAM, the effect of transmission rate changes discussed below, partially offset by less favourable temperatures in 2011	8.1	34.9
Increased transmission pool revenues year-over-year due to recovery of higher regionally-funded transmission investments partially offset by less favourable temperatures in 2011	(0.4)	2.2
Other	0.1	(0.2)
Operating revenues – regulated 2011	**$50.6**	**$204.1**

Electric Revenue

Q4 Electric Sales Volumes

GWh	**2011**	* 2010	* 2009
Residential	**196.2**	155.0	154.2
Commercial	**207.4**	146.7	144.8
Industrial	**91.1**	84.4	78.2
Other	**2.8**	2.9	2.9
Total	**497.5**	389.0	380.1

Annual Electric Sales Volumes

GWh	**2011**	* 2010	* 2009
Residential	**778.5**	591.0	591.5
Commercial	**846.4**	594.1	588.0
Industrial	**380.5**	363.0	342.0
Other	**11.4**	11.6	11.6
Total	**2,016.8**	1,559.7	1,533.1

*MAM is not included in 2010 and 2009 operating statistics.

Q4 Average Electric Revenue/MWh

	2011	*2010 (adjusted)	*2009 (adjusted)
Dollars per MWh	**$75**	$75	$68

Annual Average Electric Revenue/MWh

	2011	*2010 (adjusted)	*2009 (adjusted)
Dollars per MWh	**$72**	$71	$68

*MAM is not included in 2010 and 2009 operating statistics.

There was no change in annual average electric revenue per MWh in 2011 compared to 2010 (adjusted). Decreased transmission rates were offset by increased stranded cost rates.

The change in average electric revenue per MWh in 2010 (adjusted) compared to 2009 (adjusted) reflects increases in transmission rates on June 1, 2010, November 1, 2009 and June 1, 2009, partially offset by the impact of a stranded cost rate decrease on June 1, 2009.

Regulated Fuel for Generation and Purchased Power

Bangor Hydro has several above-market purchase power contracts pre-dating the Maine market restructuring, as well as an additional power purchase contract entered into in Q3 2011 with a wind generator. Power purchased under the older arrangements is resold to a third party at market rates as determined through a bid process administered and approved by the MPUC, while the purchased power from the wind generator is sold directly into the New England market. The difference between the cost of the power purchased under these arrangements and the revenue collected is recovered through stranded cost rates under a full reconciliation rate mechanism.

MPS has an expired power purchase contract that is currently being recovered in stranded cost rates and the related deferred asset is being amortized accordingly.

Income Taxes

Maine Utilities' are subject to corporate income tax at the statutory rate of 40.8 percent (combined US federal and state income tax rate).

CARIBBEAN UTILITY OPERATIONS

Overview

Caribbean Utility Operations includes Emera's:

- 80.1 percent investment in Light & Power Holdings Ltd. ("LPH") and its wholly-owned subsidiary Barbados Light & Power Company Ltd. ("BLPC"). BLPC is a vertically-integrated utility and the sole provider of electricity on the island of Barbados which serves approximately 123,000 customers and is regulated by the Fair Trading Commission, Barbados. The government of Barbados has granted BLPC a franchise to produce, transmit and distribute electricity on the island until 2028. BLPC is regulated under a cost-of-service model with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. BLPC's approved regulated return on assets for 2011 is 10 percent. BLPC's first rate adjustment since 1983 was approved in January 2010 and was effective March 1, 2010. A fuel pass-through mechanism ensures fuel costs are recovered. A controlling interest in LPH was acquired in January 2011, and accordingly its results are not consolidated in the 2010 and 2009 comparative information; these results contain only equity income.

- 50 percent direct and 30.4 percent indirect interest in Grand Bahama Power Company Ltd. ("GBPC"), a vertically-integrated utility and the sole provider of electricity on Grand Bahama Island. GBPC serves 19,000 customers and is regulated by GBPA, which has granted it a licensed, regulated and exclusive franchise to produce, transmit and distribute electricity on the island until 2054. There is a fuel pass-through mechanism and flexible tariff adjustment policy to ensure costs are recovered and a reasonable return earned. A controlling interest in GBPC was acquired in December 2010, and accordingly its results are not consolidated in the 2010 and 2009 comparative information; these results contain only equity income.

- 19.1 percent interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically-integrated electric utility on the island of St. Lucia. The investment in Lucelec is accounted for on the equity basis.

Review of 2011

Caribbean Utility Operations' Net Income

millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Operating revenues – regulated	**$108.0**	-	**$406.3**	-	-
Regulated fuel for generation and purchased power	**73.4**	-	**273.7**	-	-
Operating, maintenance and general (1)	**23.5**	$6.9	**87.3**	$6.9	-
Property taxes	**0.3**	-	**1.4**	-	-
Depreciation and amortization	**5.4**	-	**22.6**	-	-
Total operating expenses	**102.6**	6.9	**385.0**	6.9	-
Income from operations	**5.4**	(6.9)	**21.3**	(6.9)	-
Income from equity investments	**0.7**	(0.7)	**2.8**	4.7	$3.6
Other income (expenses), net	**0.3**	(2.6)	**35.7**	19.7	-
Interest expense, net	**2.2**	-	**8.6**	-	-
Income before provision for income taxes	**4.2**	(10.2)	**51.2**	17.5	3.6
Income tax expense	**0.5**	-	**0.7**	-	-
Net income	**3.7**	(10.2)	**50.5**	17.5	3.6
Non-controlling interest in subsidiaries	**0.6**	(2.5)	**3.7**	(2.3)	0.7
Contribution to consolidated net income	**$3.1**	$(7.7)	**$46.8**	$19.8	$2.9
Contribution to consolidated earnings per common share	**$0.03**	$(0.06)	**$0.39**	$0.17	$0.03

(1) 2010 Operating maintenance and general costs comprise costs associated with the acquisition of controlling interest in GBPC.

Caribbean Utility Operations' contribution to consolidated net income increased by $10.8 million to $3.1 million in Q4 2011 compared to a loss of $7.7 million in Q4 2010 (adjusted). For the year ended December 31, 2011, contribution to consolidated net income increased by $27.0 million to $46.8 million in 2011 compared to $19.8 million in 2010 (adjusted) and $2.9 million in 2009 (adjusted). Highlights of the net income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2009 (adjusted)		**$2.9**
Gain on initial investment in LPH		22.5
GBPC acquisition-related costs		(6.1)
Increased income from equity investment in LPH		5.4
Decreased income from equity investment in GBPC		(1.0)
Loss on acquisition of GBPC		(2.4)
Other		(1.5)
Contribution to consolidated net income – 2010 (adjusted)	**$(7.7)**	**$19.8**
Gain on initial investment in LPH recorded in 2010	-	(22.5)
Gain on acquisition of controlling interest in LPH in 2011	-	28.2
GBPC acquisition-related costs recorded in 2010	6.1	7.3
Increased income from increased investments in LPH and GBPC	1.1	9.3
Increased income due to regulatory deferral in GBPC	-	4.4
Other	3.6	0.3
Contribution to consolidated net income – 2011	**$3.1**	**$46.8**

Operating Revenues – Regulated

Q4 Operating Revenues – Regulated
millions of Canadian dollars

	2011
Residential electric revenues	$11.6
Commercial electric revenues	20.0
Industrial electric revenues	3.9
Other electric revenues	0.9
Total electric revenues	$36.4
Other – service installation revenue and fuel surcharge	71.6
Operating revenues - regulated	$108.0

Annual Operating Revenues – Regulated
millions of Canadian dollars

	2011
Residential electric revenues	$45.3
Commercial electric revenues	84.5
Industrial electric revenues	14.3
Other electric revenues	3.6
Total electric revenue	$147.7
Other – service installation revenue and fuel surcharge	258.6
Operating revenues – regulated	$406.3

Electric Revenue

Electric sales volume is primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal, with Q2 and Q3 the strongest periods, reflecting warmer weather.

Q4 Electric Sales Volumes
GWh

	2011
Residential	97.3
Commercial	179.9
Industrial	23.6
Other	5.7
Total	306.5

Annual Electric Sales Volumes
GWh

	2011
Residential	384.8
Commercial	701.1
Industrial	91.9
Other	21.8
Total	1,199.6

Q4 Average Electric Revenue/MWh

	2011
Dollars per MWh	$119

Annual Average Electric Revenue/MWh

	2011
Dollars per MWh	$123

Regulated Fuel for Generation and Purchased Power

Q4 Production Volumes
GWh

	2011
Oil	339.2

Annual Production Volumes
GWh

	2011
Oil	1,316.7

Q4 Average Unit Fuel Costs

	2011
Dollars per MWh	$216

Annual Average Unit Fuel Costs

	2011
Dollars per MWh	$208

Fuel Recovery Mechanisms

BLPC

All BLPC fuel costs are passed to customers through the fuel clause adjustment ("fuel surcharge"). Fair Trading Commission, Barbados has approved the calculation of the fuel surcharge, which is adjusted on a monthly basis. BLPC has the ability to carryover an under-recovery to later months to smooth the fuel surcharge for customers.

GBPC

The base tariff for GBPC includes a component to recover the cost of $20 USD per barrel of oil consumed by GBPC for generation of electricity. The amount by which actual fuel costs exceed $20 USD dollars per barrel is recovered or rebated through the fuel surcharge, which is adjusted on a monthly basis. The methodology for calculating the amount of the fuel surcharge has been approved by GBPA.

Income from Equity Investments

In 2011, income from equity investments included Emera's 19.1 percent investment in Lucelec only. Emera acquired controlling interests in GBPC in December 2010 and LPH in January 2011, and accordingly those investments are consolidated in 2011.

In 2010, income from equity investments included Emera's 19.1 percent interest in Lucelec, its 25 percent investment in GBPC prior to acquiring the controlling interest in December 2010, and the 38.4 percent investment in LPH, which was acquired that year. In 2009, income for equity investment included the Lucelec and GBPC investments.

Regulatory Deferrals

On July 14, 2011, GBPA approved the recovery of a $4.7 million asset impairment charge recorded in 2010. As a result, the charge was reversed through earnings in Q3 2011, and recorded as a regulatory asset, which will be amortized into income over a 25 year period commencing upon completion of the new 52 MW diesel generation unit scheduled to be on line mid-2012.

On April 12, 2011, GBPA approved, as part of the fuel surcharge, the recovery of the net costs of leasing the temporary generation required to meet peak demand for electricity until the commission of a new 52-MW power plant. The amount by which the actual cost of the temporary generation exceeds what has been recovered through the fuel surcharge has been recorded as a regulatory asset which will be amortized into income.

Income Taxes

The Caribbean Utility Operations are subject to corporate income tax at the following statutory rates:

- LPH is subject to corporate income tax at the statutory rate of 25 percent;
- BLPC is subject to corporate income tax at the statutory rate of 15 percent;
- GBPC is not subject to corporate income tax; and
- Lucelec is subject to corporate income tax at the statutory rate of 30 percent. Equity income is recorded net of tax.

PIPELINES

Overview

Pipelines comprises Emera's wholly-owned Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline") and the Company's 12.9 percent interest in the Maritimes & Northeast Pipeline ("M&NP").

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Canaport™ re-gasified liquefied natural gas ("LNG") import terminal near Saint John, New Brunswick, to markets in the northeastern United States. The pipeline, which went into service in July 2009, transports re-gasified liquefied natural gas for Repsol Energy Canada under a 25 year firm service agreement. The NEB, which regulates Brunswick Pipeline, has classified it as a Group II pipeline. Brunswick Pipeline is accounted for as a direct financing lease.

M&NP is a $2 billion, 1,400-kilometer pipeline which transports natural gas from offshore Nova Scotia to markets in Maritime Canada and the northeastern United States. The investment in M&NP is equity accounted.

Review of 2011

Pipelines' Net Income millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Brunswick Pipeline					
Operating revenues – regulated	**$12.7**	$12.0	**$49.7**	$48.9	$22.5
Other income (expense), net	**(0.2)**	0.8	**0.2**	1.4	18.9
Interest expense, net	**7.6**	7.7	**30.2**	30.6	21.5
Brunswick Pipeline net income	**4.9**	5.1	**19.7**	19.7	19.9
Income from equity investment	**2.0**	2.9	**8.2**	9.2	10.2
Contribution to consolidated net income	**$6.9**	$8.0	**$27.9**	$28.9	$30.1
Contribution to consolidated earnings per common share	**$0.06**	$0.07	**$0.23**	$0.25	$0.27

Pipelines' contribution to consolidated net income decreased by $1.1 million to $6.9 million in Q4 2011 compared to $8.0 million in Q4 2010 (adjusted). For the year ended December 31, 2011, Pipelines' contribution to consolidated net income decreased $1.0 million to $27.9 million compared to $28.9 million in 2010 (adjusted) and $30.1 million in 2009 (adjusted). Highlights of the income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2009 (adjusted)		**$30.1**
Brunswick Pipeline – Decreased net income primarily due to unfavorable change in the mark-to-market of currency hedges, partially offset by a full year of operations in 2010		(0.2)
Decreased income from equity investment primarily due to increased MN&P financing charges on the US portion of the pipeline as a result of debt recapitalization, and the recognition of a settlement in the first half of 2009 combined with a stronger CAD in 2010		(1.0)
Contribution to consolidated net income – 2010 (adjusted)	**$8.0**	**$28.9**
Brunswick Pipeline – Decreased net income during the quarter primarily due to the unfavorable change in the mark-to-market of currency hedges	(0.2)	-
Decreased income from equity investment due to lower toll rates in M&NP	(0.9)	(1.0)
Contribution to consolidated net income – 2011	**$6.9**	**$27.9**

Brunswick Pipeline

The Company records the net investment in a lease under the direct finance method, which consists of the sum of the minimum lease payments and residual value net of estimated executory costs and unearned income. This accounting method has the effect of recognizing higher revenues in the early years of the contract than would have been recorded if the toll revenues were recorded as received.

Income Taxes

Brunswick Pipeline is subject to corporate income tax at the statutory rate of 27.0 percent (combined Canadian federal and provincial income tax rate). M&NP’s equity income is recorded net of tax.

SERVICES, RENEWABLES AND OTHER INVESTMENTS

Overview

Services, Renewables and Other Investments ("SRO") includes Emera Energy ("Emera Energy"); Emera Utility Services Inc. ("EUS"); and Emera Newfoundland & Labrador Holdings Inc. ("ENL"), as well as other investments.

- Emera Energy includes:
  - Emera Energy Services, a physical energy business which purchases and sells natural gas and electricity and provides related energy asset management services.
  - Bayside Power, a 260-MW gas-fired merchant electricity generating facility in Saint John, New Brunswick.
  - Emera's 50 percent joint venture ownership of Bear Swamp, a 600-MW pumped storage hydro-electric facility in northern Massachusetts. This investment is equity accounted.

- EUS is a utility services contractor.

- ENL is a wholly-owned subsidiary of Emera focused on transmission investments related to a proposed 824-MW hydro-electric generating facility at Muskrat Falls in Labrador. These investments include an estimated $1.2 billion transmission project between Newfoundland and Nova Scotia, incorporating a 180-kilometre subsea cable ("Maritime Link Project"). In addition, together with Nalcor Energy, Newfoundland and Labrador's provincial energy crown corporation leading the project in that province, Emera is investing in the development of a $2.1 billion electricity transmission project in Newfoundland and Labrador ("Labrador-Island Transmission Link Project"). These projects are scheduled to be in service in 2017. Development costs incurred to date have been capitalized.

- Other investments include a 6.26 percent investment in Algonquin Power & Utilities Corporation ("APUC"), a 49.999 percent investment in California Pacific Utilities Ventures ("CPUV") and a 37.7 percent investment in Atlantic Hydrogen Inc. ("AHI"). These investments are equity accounted.

Review of 2011

Emera Energy and EUS are reported on an income before interest expense, net and income tax expense (recovery) ("EBIT") basis.

Services, Renewables and Other Investments Net Income millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Emera Energy	**$2.4**	$(0.3)	**$7.6**	$3.6	$10.9
EUS	**2.1**	3.0	**4.4**	7.0	1.8
Income (loss) from equity investments	**0.7**	0.2	**2.9**	(0.3)	-
Other income, net	**0.5**	-	**14.6**	-	-
Interest expense, net	**-**	0.2	**0.9**	1.2	1.7
Income tax expense (recovery)	**(0.3)**	0.9	**1.6**	0.5	(3.7)
Contribution to consolidated net income	**$6.0**	$1.8	**$27.0**	$8.6	$14.7
Bear Swamp after-tax mark-to-market adjustment	**$(0.7)**	$(2.6)	**$(0.8)**	$(8.6)	$0.7
Contribution to consolidated net income, absent the Bear Swamp after-tax mark-to-market adjustment	**$6.7**	$4.4	**$27.8**	$17.2	$14.0
Contribution to consolidated earnings per common share	**$0.05**	$0.02	**$0.22**	$0.08	$0.13
Contribution to consolidated earnings per common share, absent the Bear Swamp after-tax mark-to-market adjustment	**$0.06**	$0.04	**$0.23**	$0.15	$0.12

SRO's contribution to consolidated net income increased by $4.2 million to $6.0 million in Q4 2011 compared to net income of $1.8 million in Q4 2010 (adjusted). For the year ended December 31, 2011, contribution to consolidated net income increased $18.4 million to $27.0 million compared to $8.6 million in 2010 (adjusted) and $14.7 million in 2009 (adjusted). Highlights of the income changes are summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net income – 2009 (adjusted)		**$14.7**
Emera Energy – Decreased due primarily to an unfavourable change in the fair value of the net derivatives in Bear Swamp, lower equity income and the stronger CAD, partially offset by improved Emera Energy results		(7.3)
EUS – Increased primarily due to the successful completion of large construction projects and the expansion of the communications business		5.2
Income tax expense – Increased due to increased income		(4.2)
Other		0.2
Contribution to consolidated net income – 2010 (adjusted)	**$1.8**	**$8.6**
Emera Energy – Increased during the quarter and year-over-year due to a positive change in the fair value of the net derivatives in Bear Swamp; increased year-over-year also due to stronger energy marketing results, partially offset by the reversal of 2010 mark-to-market gains	2.7	4.0
EUS – Decreased due to reduced construction activity	(0.9)	(2.6)
Income from equity investments – Increased investments in APUC and CPUV	0.5	3.2
Other income, net – Increased year-over-year primarily due to an after-tax gain of $12.8 million on APUC subscription receipts	0.5	14.6
Income tax expense – Increased year-over-year primarily due to the taxable gain on APUC subscription receipts	1.2	(1.1)
Other	0.2	0.3
Contribution to consolidated net income – 2011	**$6.0**	**$27.0**

Emera Energy

Bear Swamp Mark-to-Market Adjustment

Bear Swamp has an agreement to supply energy and capacity to the Long Island Power Authority ("LIPA") through to 2021. Bear Swamp has contracted with its joint venture partner to provide the power necessary to produce the requirements of the LIPA contract. One of the contracts between Bear Swamp and Emera is marked-to-market through earnings, as it does not meet the stringent accounting requirements for hedge accounting.

As at December 31, 2011 the fair value of the contract was a net liability of $9.6 million (December 31, 2010 (adjusted) – $8.2 million net liability). The fair value of this derivative is subject to market volatility of power prices and will reverse over the life of the agreement as it is realized.

Other Income, Net

Other income, net includes Emera's 6.26 percent investment in APUC, 49.999 percent investment in CPUV and a 37.7 percent investment in AHI.

Income Taxes

Emera Energy is subject to corporate income tax at the statutory rate of 41.0 percent (combined US federal and state income tax rate) on its US sourced income and 30.9 percent (combined Canadian federal and provincial) on its Canada sourced income. Bear Swamp's equity income is recorded net of tax.

EUS is subject to corporate income tax at the statutory rate of 30.9 percent (combined Canadian federal and provincial).

CORPORATE

Overview

Corporate includes certain corporate-wide functions including executive management, strategic planning, treasury services, financial reporting, tax planning, business development and corporate governance. Corporate also includes interest expense and income taxes associated with corporate activities.

Review of 2011

Corporate millions of Canadian dollars	Three months ended December 31		Year ended December 31		
	2011	2010 (adjusted)	**2011**	2010 (adjusted)	2009 (adjusted)
Revenue	**$7.6**	$7.7	**$30.2**	$30.6	$30.0
Corporate costs	**4.4**	9.2	**27.3**	27.3	21.4
Interest expense	**8.5**	7.7	**33.9**	32.0	22.8
Income tax recovery	**(4.1)**	(3.5)	**(16.5)**	(14.0)	(14.5)
	(1.2)	(5.7)	**(14.5)**	(14.7)	0.3
Preferred stock dividends	**-**	-	**6.6**	3.0	-
Contribution to consolidated net income	**$(1.2)**	$(5.7)	**$(21.1)**	$(17.7)	$0.3

Revenue

Revenue consists of intercompany interest and preferred dividends from Brunswick Pipeline.

Corporate Costs

Corporate costs decreased by $4.8 million to $4.4 million in Q4 2011 compared to $9.2 million in Q4 2010 (adjusted) due primarily to decreased deferred compensation and business acquisition costs as well as foreign exchange gains resulting from a stronger CAD. Corporate costs increased $5.9 million to $27.3 million in 2010 (adjusted) compared to $21.4 million in 2009 due to acquisition-related costs.

Interest Expense

Interest expense increased $0.8 million to $8.5 million in Q4 2011 compared to $7.7 million in Q4 2010 (adjusted). Interest expense increased $1.9 million to $33.9 million for the year ended December 31, 2011 compared to $32.0 million in 2010 (adjusted) and $22.8 million in 2009 due to an increase in borrowings primarily to fund business acquisitions.

Income Tax Recovery

Income tax recovery increased by $0.6 million to $4.1 million in Q4 2011 compared to $3.5 million in Q4 2010 (adjusted) and increased $2.5 million to $16.5 million for the year ended December 31, 2011 compared to $14.0 million in 2010 (adjusted) primarily due to increased interest expense.

Preferred Stock Dividends

Preferred stock dividends increased $3.6 million to $6.6 million for the year ended December 31, 2011; compared to $3.0 million in 2010 (adjusted); and increased for the year ended December 31, 2010, by $3.0 million from nil in 2009 (adjusted), due to the issuance of preferred shares in June 2010.

OUTLOOK

Emera will continue to pursue investment opportunities related to the transformation of the energy industry to produce lower emissions. Emera has embarked on a significant capital plan to increase the Company's generation from renewable sources, to improve the transmission connections within its service territories, and to expand access to natural gas as Emera transitions to a cleaner, greener company.

Although markets in Maine and Nova Scotia are otherwise mature, the transformation of energy supply to lower emission sources has created the opportunity for organic growth within NSPI and Emera's Maine Utility Operations. The utilities expect average income growth to be 3 percent to 5 percent annually over the next five years as new investments are made in renewable generation and transmission.

NSPI

NSPI anticipates earning a regulated ROE within its allowed range in 2012. NSPI continues to implement its strategy, which is focused on regulated investments in renewable energy and system reliability projects with an annual capital expenditure plan of approximately $330 million in 2012. NSPI expects to finance its capital expenditures with funds from operations and debt.

Maine Utility Operations

USD income from Maine Utility Operations is expected to be slightly higher in 2012 compared to 2011 due to the recovery of investments in new transmission assets. In 2012, Maine Utilities expects to invest approximately $116 million USD, including approximately $78 million USD for major transmission projects.

Caribbean Utility Operations

Income from Caribbean Utility Operations is expected to be higher in 2012 compared to 2011 primarily as a result of increased capital investments in LPH and GBPC. Caribbean Utility Operations plans to invest approximately $63 million in capital programs in 2012.

Pipelines

Income from Pipelines is expected to decline marginally in 2012 as compared to 2011 as a result of capital lease accounting treatment which yields declining earnings over the life of the asset.

Services, Renewables and Other Investments

Income from Services, Renewables and Other Investments is expected to be consistent with 2011. ENL plans to invest approximately $100 million on the Maritime Link Project and Labrador-Island Transmission Link Project in 2012.

Corporate

Income from Corporate is expected to be lower in 2012 compared to 2011 due to higher interest costs due to business growth.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates cash primarily through the generation, transmission and distribution of electricity through its regulated electric utilities. The utilities' customer bases are diversified by both sales volumes and revenues among customer classes. Circumstances that could affect the Company's ability to generate cash include general economic downturns in Emera's markets, the loss of one or more large customers, regulatory decisions affecting customer rates and changes in environmental legislation. Emera's subsidiaries are capable of paying dividends to Emera provided they do not breach their debt covenants after giving effect to the dividend payment.

In addition to internally generated funds, Emera and its subsidiaries have, in aggregate access to $1.3 billion committed syndicated revolving bank lines of credit as discussed in the table below. In August 2011, Emera increased its committed syndicated bank line from $600 million to $700 million, and NSPI reduced its committed syndicated revolving bank line from $600 million to $500 million. The maturity of both facilities was extended from June 2013 to June 2015. NSPI has an active commercial paper program for up to $400 million, of which outstanding amounts are 100 percent backed by NSPI's bank line referred to above, which results in an equal amount of credit being considered drawn and unavailable.

As at December 31, 2011, the Company's total credit facilities, outstanding borrowings and available capacity were as follows:

millions of dollars	Maturity	Revolving Credit Facilities	Utilized	Undrawn and Available
Emera – Operating and acquisition credit facility	June 2015 – Revolver	$700	$263	437
NSPI – Operating credit facility	June 2015 – Revolver	500	318	182
Bangor Hydro – in USD – Operating credit facility	September 2013 – Revolver	80	66	14
Other – in USD – Operating credit facilities	2012	21	8	13

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements.

Debt Management

Emera

In February 2011, Emera filed an amended and restated short form base shelf prospectus. This amendment increased the aggregate principal amount of debt securities and preferred shares that may be offered from time to time under the short form base shelf prospectus from $500 million to $650 million. As at December 31, 2011, $150 million in preferred shares and $250 million of medium-term notes have been issued under the short form base shelf prospectus and shelf prospectus supplements.

The weighted average coupon rate of Emera's outstanding medium-term notes as at December 31, 2011 was 3.93 percent (2010 – 4.45 percent). All of the outstanding debt matures within the next ten years. The quoted yield for the same or similar issues of the same remaining maturities was 2.88 percent as at December 31, 2011 (2010 – 3.73 percent).

Emera's credit ratings issued by Dominion Bond Rating Service ("DBRS") and Standard & Poor's ("S&P") are as follows:

	DBRS	S&P
Long-term corporate	BBB (high)	BBB+
Preferred stock	Pfd-3 (high)	P-2 (Low)

NSPI

In May 2011, NSPI filed an amendment to its amended and restated short form base shelf prospectus and an amendment to its prospectus supplement for medium-term notes (unsecured). These amendments increased the aggregate principal amount of debt securities and medium-term notes that may be offered from time to time under the short form base shelf prospectus and prospectus supplement from $500 million to $800 million. As at December 31, 2011, $300 million in medium-term notes have been issued under NSPI's short form base shelf prospectus and prospectus supplement since their initial filing in 2010.

Concurrently with the Canadian filing of these amendments, NSPI also filed a registration statement with the SEC to register debt securities having an aggregate initial offering price of up to $500 million for sale in the United States. As discussed in the NSPI Developments section, on December 12, 2011, NSPI filed a post-effective amendment to its registration statement with the SEC, removing from registration all unsold debt securities as of that date.

The weighted average coupon rate on NSPI's outstanding medium-term and debenture notes as at December 31, 2011 and 2010 was 6.74 percent. Approximately 27 percent of the debt matures over the next ten years, 70 percent matures between 2021 and 2040 and 3 percent, matures in 2097. The quoted yield for the same or similar issues of the same remaining maturities was 3.51 percent as at December 31, 2011 (2010 – 4.50 percent).

NSPI's credit ratings issued by DBRS and S&P's are as follows:

	DBRS	S&P
Corporate	N/A	BBB+
Senior unsecured debt	A (low)	BBB+
Preferred stock	Pfd-2 (low)	P-2 (low)
Commercial paper	R-1 (low)	A-1 (low)

Maine Utility Operations

On January 31, 2012, Bangor Hydro completed the issue of an unsecured $70.0 million USD senior note. The Series 2012-A Senior Note bears interest at a rate of 3.61 percent per annum until January 31, 2022. The net proceeds of the note offering were used to repay borrowings under the revolving credit facility.

On April 27, 2011, MPS renewed its existing $10 million USD revolving credit facility, with a new expiration date of December 31, 2012.

On June 24, 2010, Bangor Hydro entered into a 39 month revolving credit facility for $80 million USD.

The weighted-average coupon rate on Bangor Hydro's outstanding long-term debt as at December 31, 2011 was 7.01 percent (2010 – 6.96 percent). Approximately 87 percent of the debt matures over the next 10 years; the remaining matures in 2022. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 2.54 percent as at December 31, 2011 (2010 – 3.81 percent).

The weighted-average coupon rate on MPS' outstanding long-term debt as at December 31, 2011 and 2010 was 4.46 percent. All of the debt matures over the next 10 years. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 3.58 percent as at December 31, 2011 (2010 – 4.85 percent).

Bangor Hydro and MPS have no public debt, and accordingly have no requirement for public credit ratings. Both utilities believe that their credit facility provides adequate access to capital to support current operations and a base level of capital expenditures. For additional capital needs, both utilities expect to have sufficient access to competitively priced funds in the unsecured debt market.

Caribbean Utility Operations

On January 25, 2012, GBPC entered into an unsecured credit agreement with Scotiabank (Bahamas) Limited in the amount of $56.2 million USD. The proceeds of the credit agreement will be used to finance the construction of a 52-MW power plant on Grand Bahama Island. The credit agreement bears interest at a rate of the three month LIBOR rate plus 1.2 percent and is repayable in forty equal, consecutive quarterly installments over a ten year period. The payments commence at the earlier of six months after the completion of the construction of the power plant or January 31, 2013.

In October 2011, GBPC entered into a 12 month revolving credit facility for $11 million Bahamian dollars.

The weighted-average coupon rate on BLPC's' outstanding long-term debt as at December 31, 2011, was 6.30 percent. Approximately 77 percent of the debt matures over the next 10 years; the remaining issue matures in 2025. The market weighted average interest rate is based on the last rate of debt issuances of 6.85 percent.

The weighted-average coupon rate on GBPC's outstanding long-term debt as at December 31, 2011, was 6.64 percent (2010 – 6.61 percent). Approximately 66 percent of the debt matures over the next 10 years; the remaining issue matures in 2023. The market weighted average interest rate is 7.00 percent as at December 31, 2011 (2010 – 5.86 percent), based on the last rate of debt issuances.

BLPC and GBPC have no public debt, and accordingly have no requirement for public credit ratings. Both utilities believe their credit facilities provide adequate access to capital to support current operations and a base level of capital expenditures. For additional capital needs, both utilities expect to have sufficient access to competitively priced funds in the unsecured debt market.

Contractual Obligations

As at December 31, 2011, commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt (1)	$3,307.0	$30.0	$380.9	$301.5	$591.9	$254.8	$1,747.9
Purchased power (2)	1,840.8	100.3	113.4	117.6	117.8	118.0	1,273.7
Coal, biomass, oil and natural gas supply	1,188.1	233.0	159.9	109.5	63.4	22.4	599.9
Pension and post-retirement obligations (3)	757.9	66.3	67.3	66.9	60.1	51.5	445.8
Asset retirement obligations	361.1	5.3	2.3	2.4	2.0	3.1	346.0
Transportation (4)	150.0	72.5	29.3	26.8	16.5	2.2	2.7
Long-term service agreements (5)	35.1	12.2	11.3	6.1	5.0	0.5	-
Capital projects	78.2	56.3	3.5	0.6	3.9	-	13.9
Leases (6)	32.3	3.9	3.3	3.2	3.1	2.8	16.0
Other	18.2	5.2	3.8	3.6	3.6	1.0	1.0
	$7,768.7	$585.0	$775.0	$638.2	$867.3	$456.3	$4,446.9

(1) Long-term debt: Emera's and NSPI's revolving credit facilities mature in June 2015.
(2) Purchased power: annual requirement to purchase 100 percent of electricity production from independent power producers over varying contract lengths up to 25 years.
(3) Pension and post-retirement obligations: are based on regulatory requirements and assume that members stop accruing service effective December 31, 2011. As most of Emera's defined benefit pension plans still allow continued accrual of service and each plan's contribution requirements are reassessed on a regular basis, actual future pension contributions will differ from the amounts shown.
(4) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on various pipelines.
(5) Long-term service agreements: outsourced management of the Company's computer and communication infrastructure, vegetation management and maintenance of certain generation equipment.
(6) Leases: operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

Capital Expenditures

Capital expenditures for 2011, including AFUDC, were approximately $515 million and included:

- $320 million in NSPI;
- $100 million in Maine Utility Operations;
- $70 million in Caribbean Utility Operations; and
- $25 million in Services, Renewables and Other Investments.

Forecasted Gross Consolidated Capital Expenditures

For the year ended December 31, 2012 millions of Canadian dollars	NSPI	Maine Utility Operations	Caribbean Utility Operations	Services, Renewable and other investments	Corporate	Total
Generation	$142	NA	$45	$13	-	$200
Transmission	68	$83	11	100	-	262
Distribution	72	18	3	-	-	93
Facilities, equipment, vehicles and other	48	16	4	-	-	68
Total	$330	$117	$63	$113	-	$623

Significant Individual Capital Projects

millions of Canadian dollars	Nature of Project	Pre-2012 Spending	2012 Forecast	Post-2012 Forecast	Expected year of completion
NSPI	Port Hawkesbury Biomass	$143	$56	$8	2013
	Transmission	-	1	11	2013
	LED Streetlight Conversion	-	6	94	2016
	Marshall Falls Hydro Upgrade	-	3	15	2017
Maine Utility Operations	Transmission	65	45	79	2012 – 2014
	Technology	3	11	7	2014
Caribbean Utility Operations	West Sunrise Plant	41	38	-	2012
Services, Renewables and other investments	Bayside Power Gas Turbine Upgrade	9	13	4	2012
	Maritime Link Project	10	30	1,160	2017
	Labrador-Island Transmission Project	-	70	530	2017

PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three year period. The cash required in 2012 for defined benefit pension plans will be approximately $73.7 million (2011 – $51.9 million actual). All pension plan contributions are tax deductible and will be funded with cash from operations.

Emera's defined benefit pension plans employ a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return given the Company's goal of preserving capital within an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation pension assets are overseen by external investment managers per the pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of Canadian and global equities, domestic bonds, and short-term investments. Emera reviews investment manager performance on a regular basis and adjusts the plans' asset mixes as needed in accordance with the pension plan's investment policy.

Emera's projected contributions to defined contribution pension plans are $6.5 million for 2012 (2011 – $6.2 million actual).

OFF-BALANCE SHEET ARRANGEMENTS

Upon privatization of the former provincially owned NSPC in 1992, NSPI became responsible for managing a portfolio of defeasance securities, which as at December 31, 2011, totaled $1.0 billion. The securities are held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), an affiliate of the Province of Nova Scotia. NSPI is responsible for ensuring the defeasance securities provide the principal and interest streams to match the related defeased NSPC debt. Approximately 73 percent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio; the remaining defeasance portfolio has a market value higher than the related debt, reducing the future risk of this portion of the portfolio.

Emera had the following guarantees and letter of credits as at December 31, 2011:

- NSPI has provided a limited guarantee for the indebtedness of Renewable Energy Services Ltd. ("RESL"). The guarantee is up to a maximum of $23.5 million. As at December 31, 2011, RESL's indebtedness under the loan agreement was $21.9 million. NSPI holds a security interest in the present and future assets of RESL.

- Emera has provided a guarantee to LIPA on behalf of Bear Swamp for Bear Swamp's long-term energy and capacity supply agreement ("Agreement") with LIPA, which expires on April 30, 2021. The guarantee is for 50 percent of the relevant obligations under the Agreement up to a maximum of $18.6 million USD. As at December 31, 2011, the fair value of the Agreement is positive.

- Emera has provided a guarantee to the Bank of Nova Scotia on behalf of Bear Swamp for Bear Swamp's interest rate swaps entered into between Bear Swamp and the Bank of Nova Scotia which expires on May 9, 2012. The guarantee is for 50 percent of the relevant obligations up to a maximum of $1.0 million USD. In the event Emera was required to make a payment to the Bank of Nova Scotia under this guarantee, the guarantee provides that Emera is able to seek recovery from Bear Swamp's creditors after Bear Swamp has paid its debts in full. As at December 31, 2011, the fair value of that agreement is positive.

- At the request of Emera and its subsidiaries, a financial institution has issued standby letters of credit in the amount of $11.4 million for the benefit of third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one year term and are renewed annually as required.

- A financial institution has issued a standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2012 and is renewed annually. The amount committed as at December 31, 2011 was $22.5 million.

- A financial institution has issued a standby letter of credit to secure obligations under an unfunded pension plan in BHE. The letter of credit expires in October 2012 and is renewed annually. The amount committed as at December 31, 2011 was $2.2 million USD.

- A financial institution has been issued direct pay letters of credit totaling $23.9 million USD to secure principal and interest payments related to Maine Public Utilities Financing Bank bonds issued on behalf of MPS, related to qualifying distribution assets.

No liability has been recognized on the consolidated balance sheets related to any potential obligation under these guarantees and letters of credit.

TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera purchased natural gas transportation capacity from M&NP, an investment under significant influence of the Company, totaling $10.6 million (2010 – $12.8 million) for the three months ended December 31, 2011, and $47.3 million (2010 – $55.1 million) for the year ended December 31, 2011. The amount is recognized in “Regulated fuel for generation and purchased power” or netted against energy marketing margin in “Non-regulated operating revenues” and is measured at the exchange amount. As at December 31, 2011, the amount payable to the related party was $3.3 million (December 31, 2010 – $3.9 million), and is under normal interest and credit terms.

DIVIDENDS AND PAYOUT RATIOS

Emera Incorporated’s common dividend rate was $1.31 ($0.3250 per quarter in Q1, Q2 and Q3 and $0.3375 in Q4) per common share in 2011 and $1.16 ($0.2725 in Q1, $0.2825 in Q2 and Q3 and $0.3250 in Q4) per common share in 2010, representing a payout ratio of approximately 65.8 percent in 2011 and 69.2 percent in 2010.

On September 23, 2011, Emera’s Board of Directors approved an increase in the annual common share dividend rate from $1.30 to $1.35, and accordingly declared a quarterly dividend of $0.3375 per common share.

In February 2010, the Board of Directors approved a quarterly dividend increase, effective May 3, 2010, to $0.2825 per common share, and in September 2010, approved a further increase to $0.3250 effective November 1, 2010 reflecting an increase on an annualized basis to $1.30 per common share.

Effective September 25, 2009, Emera changed its Common Shareholders Dividend Reinvestment and Share Purchase Plan to provide for a discount of up to 5 percent from the average market price of Emera’s common shares for common shares purchased in connection with the reinvestment of cash dividends under this Plan.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Emera’s risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management practices are overseen by the Board of Directors. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operations.

The Company manages its exposure to normal operating and market risks relating to commodity prices, foreign exchange and interest rates using financial instruments consisting mainly of foreign exchange forwards and swaps, interest rate options and swaps, and coal, oil and gas futures, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. Collectively these contracts are considered “derivatives”.

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales (“NPNS”) exception. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company’s business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty credit worthy. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts where the criteria are no longer met.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and can be proven to effectively hedge the identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to Accumulated Other Comprehensive Loss (“AOCL”) and recognized in income in the same period the related hedged item is realized. Any ineffective portion of the change in the fair value of the cash flow hedges is recognized in net income in the reporting period.

Where the documentation or effectiveness requirements are not met, the derivatives are recognized at fair value, with any changes in fair value recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

Derivatives entered into by NSPI that are documented as economic hedges, and for which the NPNS exception has not been taken, receive regulatory deferral as approved by the UARB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized when the derivatives settle. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates through the FAM.

Derivatives that do not meet any of the above criteria are designated as HFT and are recognized on the balance sheet at fair value. All gains and losses are recognized in net income of the period unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category when another accounting treatment applies.

Hedging Items Recognized on the Balance Sheets

The Company has the following categories on the balance sheet related to derivatives in valid hedging relationships:

As at millions of Canadian dollars	**December 31 2011**	December 31 2010 (adjusted)
Derivative instrument assets (current and other assets)	**$5.7**	$7.0
Derivative instrument liabilities (current and long-term liabilities)	**(27.8)**	(18.3)
Net derivative instrument liabilities	**$(22.1)**	$(11.3)

Hedging Impact Recognized in Net Income

The Company recognized the following gains (losses) related to the effective portion of hedging relationships under the following categories:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2011	2010 (adjusted)	**2011**	2010 (adjusted)
Regulated operating revenues	**$0.3**	-	**$2.7**	-
Non-regulated fuel and purchased power	**(2.3)**	$(2.1)	**(7.0)**	$(8.6)
Other income (expenses), net	**(0.2)**	-	**(0.3)**	-
Effectiveness net losses	**$(2.2)**	$(2.1)	**$(4.6)**	$(8.6)

The effectiveness gains (losses) reflected in the above table would be offset in net income by the change in the hedged item realized in the period.

The Company recognized in net income the following gains (losses) related to the ineffective portion of hedging relationships under the following categories:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2011	2010 (adjusted)	**2011**	2010 (adjusted)
Non-regulated fuel and purchased power	**$0.5**	-	**$(0.4)**	-
Ineffectiveness gains (losses)	**$0.5**	-	**$(0.4)**	-

Regulatory Items Recognized on the Balance Sheets

The Company has the following categories on the balance sheet related to derivatives receiving regulatory deferral:

As at millions of Canadian dollars	**December 31 2011**	December 31 2010 (adjusted)
Derivative instrument assets (current and other assets)	**$44.5**	$59.9
Regulatory assets (current and other assets)	**46.3**	34.2
Derivative instrument liabilities (current and long-term liabilities)	**(46.3)**	(34.2)
Regulatory liabilities (current and long-term liabilities)	**(44.5)**	$(59.9)
Net asset (liability)	**-**	-

Regulatory Impact Recognized in Net Income

The Company recognized the following (losses) gains related to derivatives receiving regulatory deferral as follows:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2011	2010 (adjusted)	**2011**	2010 (adjusted)
Other income (expenses), net	**-**	$1.0	**-**	$1.5
Regulated fuel for generation and purchased power	**$(3.8)**	(10.9)	**$(21.3)**	(66.8)
Net losses	**$(3.8)**	$(9.9)	**$(21.3)**	$(65.3)

Held-for-trading Items Recognized on the Balance Sheets

The Company has the following categories on the balance sheet related to HFT derivatives:

As at millions of Canadian dollars	**December 31 2011**	December 31 2010 (adjusted)
Derivative instruments assets (current and other assets)	**$16.7**	$18.8
Derivative instruments liabilities (current and long-term liabilities)	**(14.7)**	(13.2)
Net derivative instrument assets	**$2.0**	$5.6

Held-for-trading Items Recognized in Net Income

The Company has recognized the following realized and unrealized gains (losses) with respect to HFT derivatives in net income:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31	
	2011	2010 (adjusted)	**2011**	2010 (adjusted)
Non-regulated operating revenues	**$4.0**	$6.2	**$14.0**	$21.2
Other income (expenses), net	**0.2**	0.9	**(0.1)**	2.7
Net gains	**$4.2**	$7.1	**$13.9**	$23.9

Business Risks

Measurement of Risk

Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach. Certain risk management activities for Emera are overseen by the Enterprise Risk Management Committee to ensure such risks are appropriately assessed, monitored and controlled within predetermined risk tolerances established through approved policies.

The Company's risk management activities are focused on those areas that most significantly impact profitability, quality of income and cash flow. These risks include, but are not limited to, exposure to commodity prices, foreign exchange, acquisition risk, interest rates, commercial relationships, credit, labour, weather and regulatory risks, and changes in environmental legislation.

In this section, Emera describes some of the principal risks management believes could materially affect its business, revenues, operating income, net income, net assets or liquidity or capital resources. The nature of risk is such that no list can be comprehensive, and other risks may arise or risks not currently considered material may become material in the future.

Commodity Price Risk

A large portion of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts. In addition, the adoption and implementation of FAMs in certain subsidiaries has further helped manage this risk.

Coal/Petroleum Coke

A substantial portion of NSPI's coal and petroleum coke ("petcoke") supply comes from international suppliers, which was contracted at or near the market prices prevailing at the time of contract. The Company has entered into fixed-price and index price contractual arrangements for coal with several suppliers as part of the fuel procurement portfolio strategy. All index-priced contractual arrangements are matched with a corresponding financial instrument to fix the price. The approximate percentage of coal and petcoke requirements contracted as at December 31, 2011 are as follows:

2012 – 94 percent
2013 – 32 percent
2014 – 15 percent

Heavy Fuel Oil

NSPI manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options, and forward contracts. For 2012 and 2013, NSPI currently does not have heavy fuel oil hedging requirements due to favourable natural gas pricing.

BLPC and GBPC do not use derivatives to manage the changes in market price of heavy fuel oil. GBPC pays the spot market rate, and BLPC's fuel pricing is based on the three-day average market price.

Natural Gas

NSPI has entered into multi-year contracts to purchase approximately 38,400 mmbtu of natural gas per day in 2012, and 20,100 mmbtu of natural gas per day in 2013. Volumes exposed to market prices are managed using financial instruments where the fuel is required for NSPI's generation; and the balance is sold against market prices when available for resale. As at December 31, 2011, amounts of natural gas volumes that have been economically and/or financially hedged are approximately as follows:

2012 – 83 percent
2013 – 31 percent

Foreign Exchange Risk

The Company enters into foreign exchange forward and swap contracts to limit exposure on foreign currency transactions such as fuel purchases, revenue streams and capital expenditures.

NSPI

The risk due to fluctuation of the CAD against the USD for fuel purchases in NSPI is measured and managed. In 2012, NSPI expects approximately 63 percent of its anticipated net fuel costs to be denominated in USD. Forward contracts to buy $256.0 million USD were in place as at December 31, 2011 at a weighted average rate of $0.9912, representing 81 percent of 2012's anticipated USD requirements. Forward contracts to buy $752.0 million USD in 2013 through 2016 at a weighted average rate of $1.0096 were in place as at December 31, 2011. These contracts cover 60 percent of anticipated USD requirements in these years. As at December 31, 2011, there were no fuel-related foreign exchange swaps outstanding.

Bayside Power

Bayside Power uses foreign exchange forward contracts to hedge the currency risk for capital projects denominated in foreign currencies. Forward contracts to buy €9.6 million were in place as at December 31, 2011 at a weighted average rate of $1.3770 for capital projects in 2012. Forward contracts to buy €2.8 million were in place as at December 31, 2011 at a weighted average rate of $1.3951 for capital projects in 2015.

Brunswick Pipeline

Brunswick Pipeline uses forward contracts to hedge the currency risk associated with revenue streams denominated in foreign currencies. Forward contracts to sell $53.8 million USD in 2012 were in place as at December 31, 2011 at an average rate of $1.0654 and sell $78 million USD in 2013 through 2016 at a weighted average rate of $1.0591. These contracts cover 95 percent of anticipated USD revenue inflows in 2012 and 33 percent of anticipated USD revenue inflows in 2013 through 2016.

Acquisition Risk

The risks associated with Emera's acquisition strategy include the availability of suitable acquisition candidates, obtaining the necessary regulatory approval for any acquisition and assimilating and integrating acquired companies into the Company. In addition, potential difficulties inherent in acquisitions may adversely affect the results of an acquisition. These include delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies from completed transactions.

Emera mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

Interest Rate Risk

Emera utilizes a combination of fixed and variable rate debt financing for operations and capital expenditures resulting in an exposure to interest rate risk. The Company seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt. Floating-rate debt is estimated to represent approximately 15 percent of total debt in 2012. The Company has two interest rate hedging contracts outstanding as at December 31, 2011, fixing the variable interest rates on $22.6 million USD of Maine Public Utilities Financing Bank bonds at MPS.

Commercial Relationships Risk

NSPI

For the year ended December 31, 2011, NSPI's five largest customers contributed approximately 13.3 percent (2010 – 14.7 percent) of electric revenues. The loss of a large customer could have a material effect on NSPI's operating revenues. NSPI works to mitigate this risk through the regulatory process.

NSPI's largest customer was granted creditor protection under the Companies' Creditors Arrangement Act ("CCAA"), and suspended operations in September 2011. This customer contributed approximately 6.0 percent (2010 – 7.9 percent) of NSPI's electric revenues for the year ended December 31, 2011. NSPI is working to recover an outstanding receivable owing from this customer through the CCAA claims process, including a claim for set-off against amounts owing from NSPI to the customer that exceeds the amount receivable. The 2012 General Rate Decision, approved by the UARB, provides for any unrecovered non-fuel electric charges in 2012 related to this customer to be deferred and recovered beginning in 2013.

Brunswick Pipeline

Brunswick Pipeline has a 25 year firm service agreement with Repsol Energy Canada ("REC"). The pipeline was used solely in 2011 and 2010 to transport natural gas from the Canaport LNG terminal in Saint John, New Brunswick to the United States border for REC. The risk of non-payment is mitigated as Repsol YPF, S.A ("Repsol"), the parent company of REC, has provided Brunswick Pipeline with a guarantee for all RECs' payment obligations under the firm service agreement. As at December 31, 2011 the net investment in direct financing lease with Repsol was $493.8 million. Repsol is rated investment grade BBB/Baa1; credit ratings and other company information are monitored on an ongoing basis. There is currently no allowance for credit losses related to this agreement.

Bayside Power

Bayside Power sells all its generation during the months of November through March to NB Power in accordance with a long-term purchase power agreement ("PPA"). Revenue from this PPA contributed 46.5 percent (2010 – 48.0 percent) to Bayside Power's electric revenues for the year ended December 31, 2011. The PPA expires March 31, 2021, with an option to renew for an additional five year term, provided both parties consent to the renewal.

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers, energy marketing collateral deposits and derivative assets. Credit risk is the potential loss from counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties and deposits or collateral are requested on any high risk accounts.

Labour Risk

Certain Emera employees are subject to collective labour agreements. Approximately 55 percent of the full-time and term employees at NSPI, BLPC, GBPC, Bangor Hydro, EUS, and MPS are represented by local unions. Approximately 45 percent of the labour force is covered by collective labour agreements that will expire within the next twelve months. Emera seeks to manage this risk through ongoing discussions with the local unions.

Weather Risk

Shifts in weather patterns affect electric sales volumes and associated revenues. Extreme weather events generally result in increased operating costs associated with restoring power to customers. Emera responds to significant weather event related outages according to each subsidiary's respective Emergency Services Restoration Plan.

Regulatory Risk

The Company's rate-regulated subsidiaries are subject to risk in the recovery of costs and investments in a timely manner. The Company manages this risk through ongoing stakeholder consultation and engagement on aspects such as utility operations, rate filings and capital plans.

NSPI

NSPI faces risk with respect to the recovery of costs and investments in a timely manner. As a regulated, cost-of-service utility with an obligation to serve, NSPI must obtain regulatory approval to change general electricity rates and riders. Costs and investments can be recovered after and once the UARB has approved recovery in adjustments to rates or riders, which normally requires a public hearing process.

During public hearing processes, consultants and customer representatives scrutinize the Company's costs, actions and plans, and the UARB determines whether to allow recovery and to adjust rates based upon NSPI's evidence and any contrary evidence from other hearing participants. The Company manages this regulatory risk through transparent regulatory disclosure, ongoing stakeholder consultation and multi-party engagement on aspects such as utility operations, rate filings and capital plans. The Company employs a collaborative regulatory approach through technical conferences and negotiated settlements.

Bangor Hydro

Bangor Hydro's business consists of three primary components which are each governed by their own regulatory structure. The components include distribution, transmission and stranded cost recoveries.

Distribution Operations

Bangor Hydro's distribution business operates under the regulation of the MPUC and operates under a traditional cost-of-service regulatory structure. Distribution rates are set based on an allowed ROE of 10.2 percent, on a common equity component of 50 percent.

Transmission Operations

Bangor Hydro's local transmission rates are set by the FERC annually on June 1, based upon a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted transmission investments and expenses. The allowed ROE for these local transmission investments is 11.14 percent. The common equity component is based upon the prior calendar year actual average balances. On June 1, 2011, Bangor Hydro's local transmission rates decreased by approximately 10 percent (2010 - increased 37 percent).

Bangor Hydro's bulk transmission assets are managed by the ISO-New England ("ISO") as part of a region-wide pool of assets. The ISO manages the regions' bulk power generation and transmission systems and administers the open access transmission tariff. Currently, Bangor Hydro, along with all other participating transmission providers, recovers the full cost of service for their transmission assets, from distribution companies in New England, based on a regional formula that is updated on June 1 of each year. This formula is based on prior year regionally funded transmission investments and expenses, adjusted for current year forecasted investments and expenses. Bangor Hydro's allowed ROE for these transmission investments ranges from 11.64 percent to 12.64 percent, and the common equity component is based upon the prior calendar year average balances. The participating transmission providers are also required to contribute to the cost of service of such transmission assets on a ratable basis according to the proportion of the total New England load that their customers represent.

On June 1, 2010, Bangor Hydro's regional transmission revenue requirement increased by 22 percent; and on June 1, 2011, it increased by a further 9 percent.

Stranded Cost Recoveries

Electric utilities in Maine are entitled to recover all prudently incurred stranded costs resulting from the restructuring of the industry in 2000 that could not be mitigated or that arose as a result of rate and accounting orders issued by the MPUC. Generally, the regulatory rates to recover stranded costs are set every three years on a levelized basis and determined under a traditional cost of service approach.

In May 2011, the MPUC approved an approximate 27 percent increase in Bangor Hydro's stranded cost rates for the period of June 1, 2011 to February 28, 2014. The increased stranded cost revenues are offset, for the most part, by changes in regulatory amortizations, purchased power expense and resale of purchased power. The allowed ROE used in setting these new stranded cost rates is 7.4 percent, with a common equity component of 48 percent.

While the stranded cost revenue requirements differ throughout the period due to changes in annual stranded costs, the actual annual stranded cost revenues are the same during the period. To levelize the impact of the varying revenue requirements, cost or revenue deferrals are recorded as a regulatory asset or liability, and addressed in subsequent stranded cost rate proceedings, where customer rates are adjusted accordingly.

MPS

Similar to Bangor Hydro, MPS' business consists of three primary components which are each governed by their own regulatory structure. The components are distribution, transmission and stranded cost recoveries.

Distribution Operations

MPS' distribution business operates under the regulation of the MPUC and operates under a traditional cost-of-service regulatory structure. Distribution rates are set based on an allowed ROE of 10.2 percent, on a common equity component of 50 percent.

Transmission Operations

MPS local transmission rates are set annually based on a formula through its OATT. Rates derived from the previous calendar year results go into effect June 1 for wholesale customers and July 1 for retail customers. The allowed ROE for transmission operations is 10.5 percent, and is based on the actual prior calendar year common equity balances. The allowed ROE is determined by negotiation with customers in the formula change years of the OATT, which occur every three years. The last OATT formula change year was 2009. On June 1, 2011, MPS' local transmission rates increased by 3 percent for wholesale customers (2010 – increased 63 percent) and by 4 percent for retail customers (2010 – increased by 64 percent) on July 1, 2011.

MPS' electric service territory is not interconnected to the New England bulk power systems, and MPS is not a member of ISO New England.

Stranded Cost Recoveries

In December 2011, the MPUC approved MPS' stranded cost rates for the three-year period January 1, 2012 through December 31, 2014. This revised three-year agreement, which amortizes essentially all of MPS' remaining stranded costs, has an ROE of 7.2 percent and a common equity component of 50 percent. Any residual stranded costs remaining after December 31, 2014 will be recovered in future rate proceedings.

The Barbados Light & Power Company Limited

BLPC, a wholly-owned subsidiary of LPH, is the sole electric utility on the island of Barbados. BLPC is subject to regulation under the Utilities Regulation (Procedural) Rules 2003 ("Rules") by Fair Trading Commission, Barbados, an independent regulator. The Rules give the Fair Trading Commission, Barbados utility regulation functions which include establishing principles for arriving at rates to be charged, monitoring the rates charged to ensure compliance, and setting the maximum rates for regulated utility services. The government of Barbados has granted BLPC a franchise to produce, transmit and distribute electricity on the island until 2028.

BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and providing an appropriate return to investors. BLPC's approved regulated return on assets for 2011 is 10 percent.

BLPC's first rate adjustment since 1983 was approved in January 2010 and was effective March 1, 2010.

All BLPC fuel costs are passed to customers through the fuel surcharge. Fair Trading Commission, Barbados has approved the calculation of the fuel surcharge, which is adjusted on a monthly basis.

BLPC has the ability to carryover an under-recovery to later months to smooth the fuel surcharge for customers.

Grand Bahama Power Company Limited

GBPC is the sole utility operator on Grand Bahama Island. GBPA regulates the utility and has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit, and distribute electricity on the island until 2054. There is a fuel pass through mechanism and flexible tariff adjustment policy to ensure that costs are recovered and a reasonable return earned.

The base tariff for GBPC includes a component to recover the cost of $20 USD per barrel of oil consumed by GBPC for generation of electricity. The amount by which actual fuel costs exceed $20 USD dollars per barrel is recovered or rebated through the fuel surcharge, which is adjusted on a monthly basis. The methodology for calculating the amount of the fuel surcharge has been approved by GBPA.

Changes in Environmental Legislation

NSPI is subject to regulation by federal, provincial, state, regional, and local authorities with regard to environmental matters primarily related to its utility operations. Changes to climate change and air emissions standards could adversely affect utility operations.

In addition to imposing continuing compliance obligations, there are laws, regulations and permits authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is material to NSPI. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on NSPI.

Conformance with legislative and NSPI requirements are verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the 2011 and 2010 audits.

NSPI is committed to operating in a manner that is respectful and protective of the environment, and in full compliance with legal requirements and Company policy. NSPI has implemented this policy through development and application of environmental management systems.

Climate Change and Air Emissions

Greenhouse Gas Emissions

NSPI has stabilized, and in recent years, reduced greenhouse gas emissions. This has been achieved by energy efficiency and conservation programs, increased use of natural gas and the addition of new renewable energy sources to the generation portfolio.

Greenhouse gas emissions from NSPI facilities have been capped beginning in 2010 through to 2020. The regulations allow for multi-year compliance periods recognizing the variability in electricity supply sources and demand. Over the decade, the caps will be achieved by a combination of additional renewable generation, import of non-emitting energy, and energy efficiency and conservation.

In 2011, Environment Canada announced proposed regulations for a new national carbon dioxide framework for the electricity sector in Canada. These proposed regulations would apply to new coal-fired electricity generation units; and existing coal-fired electricity generation units that have reached the end of their deemed economic life of forty-five years after commissioning. These proposed regulations will be effective July 1, 2015. Nova Scotia's existing greenhouse gas regulations require reductions in NSPI's emissions similar to those reflected in the federal framework. NSPI is engaged with federal and provincial agencies in reviewing the implications of this federal framework and its alignment with its current operating plans under existing Nova Scotia regulations.

Renewable Energy

The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI's generation mix. The target date for 5 percent of electricity to be supplied from post-2001 sources of renewable energy, owned by independent power producers, was extended to 2011 from 2010. The target for 2013, which requires an additional 5 percent of renewable energy, is unchanged.

On May 19, 2011 the Nova Scotia Government approved The Electricity Act (Amended) to facilitate the eligibility of energy from the Lower Churchill Project in Labrador as a resource for meeting Nova Scotia's renewable electricity targets. The amendment requires regulations to be developed that increase the percentage of renewable energy in the generation mix from the planned 25 percent in 2015, to 40 percent by 2020.

Mercury, Nitrogen Oxide and Sulphur Dioxide Emissions

NSPI completed a capital program to add sorbent injection to each of the seven pulverized fuel coal units in 2010 at a cost of $17.3 million. This was put in place to address planned reductions in mercury emissions limits, which are set out in the following table:

Year	Mercury Emissions Limit (kg)
2009	168
2010	110
2011 – 2012	100
2013	85
2014 – 2019	65
2020	35

Any mercury emission above 65 kg, between 2010 and 2013, must be offset by lower emissions in the 2014 to 2020 period.

NSPI completed its capital program of retrofitting low nitrogen oxide combustion firing systems on six of its seven pulverized fuel coal units in early 2009 at a cost of $23.3 million. NSPI now meets the nitrogen oxide emission cap of 21,365 tonnes per year established by the Nova Scotia Government effective 2010. These investments, combined with the purchasing of low sulphur coal, allows NSPI to meet the provincial air quality regulations.

NSPI will meet ever-reducing sulphur dioxide emission cap requirements through the use of a blend of net lower sulphur content solid fuel.

Compared to historical levels, NSPI will have reduced mercury emissions by 60 percent effective 2014, nitrogen oxide by 40 percent effective 2009 and sulphur dioxide by 50 percent effective 2010.

DISCLOSURE AND INTERNAL CONTROLS

The Company, under the supervision and participation of management, including the Chief Executive Officer and Chief Financial Officer, has designed as at December 31, 2011 disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR") as those terms are defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109").

As permitted, the Company has limited the scope of its design of DC&P and ICFR by excluding the controls, policies and procedures at LPH, which was acquired on January 25, 2011. Summary financial information about the acquisition is included in Note 18 of the Consolidated Financial Statements as at and for the year ended December 31, 2011 and 2010. The relative size of the entity has not materially changed since its acquisition dates.

Pursuant to Section 404(c) of the Sarbanes-Oxley Act of 2002 (“SOX”), as added by Section 989G of the Dodd-Frank Wall Street Reform and Consumer Protection Act, the requirement under Section 404(b) of SOX to file an auditor attestation report on an issuer’s ICFR does not apply with respect to any audit report prepared for an issuer that is neither an accelerated filer nor a large accelerated filer, as defined in Rule 12b-2 under the Exchange Act. NSPI is currently not an accelerated filer or a large accelerated filer and, therefore, is not required to file attestation reports on its ICFR. As previously noted, in December 2011, NSPI made the necessary filings to terminate its SEC reporting obligations. As a new registrant, Emera is not required to include an attestation report on its ICFR in its first Annual Report to be filed with the SEC for the year ending December 31, 2011, but would be required to include an attestation report in its subsequent Annual Reports for any year in which it is an accelerated filer or a large accelerated filer.

The Chief Executive Officer and the Chief Financial Officer have caused to be evaluated under their supervision, with the assistance of company employees, the effectiveness of the Company’s DC&P and ICFR and based on that evaluation, have concluded DC&P and ICFR were effective at December 31, 2011.

There have been no changes in Emera or its consolidated subsidiaries’ ICFR during the period beginning on January 1, 2011 and ending on December 31, 2011, which have materially affected, or are reasonably likely to materially affect ICFR.

SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company’s estimates on an on-going basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made. Significant areas requiring the use of management estimates relate to rate-regulation, the determination of pension and other post-retirement employee benefits, unbilled revenue, useful lives for depreciable assets, income taxes, asset retirement obligations and goodwill impairment assessments. Actual results may differ from these estimates.

Rate Regulation

The rate-regulated accounting policies of NSPI, Bangor Hydro, MPS, BLPC, GBPC and Brunswick Pipeline may differ from accounting policies for non-rate-regulated companies. NSPI, Bangor Hydro, MPS, BLPC and GBPC accounting policies are subject to examination and approval by their respective regulators. These accounting policy differences occur when the regulators render their decisions on rate applications or other matters and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on the expectation of the future actions of the regulators.

If the regulators’ future actions are different from their previous rulings, the timing and amount of the recovery of liabilities and refund of assets, recorded or unrecorded, could be significantly different from that reflected in the financial statements.

Pension and Other Post-Retirement Employee Benefits

The Company provides post-retirement benefits to employees, including defined benefit pension plans. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The benefit cost and accrued benefit obligation for employee future benefits included in annual compensation expenses are affected by employee demographics, including age, compensation levels, employment periods, contribution levels and earnings on plan assets.

Changes to the provision of the plan may also affect current and future pension costs. Benefit costs may also be affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation and benefit costs.

The pension plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

Emera's accounting policy is to amortize the net actuarial gain or loss, which exceeds 10 percent of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period, which is currently 9 years. Emera's use of smoothed asset values further reduces the volatility related to the amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

The discount rate used to determine benefit costs is based on the yield of high quality long-term corporate bonds in each operating entity's country. The discount rate is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year rounded to the nearest 25 basis points. For benefit cost purposes, NSPI's rate was 5.50 percent for 2011 (2010 – 6.50 percent) and Bangor Hydro's rate was 5.60 percent for 2011 (2010 – 6.00 percent). MPS' rate was 5.40 for 2011 (2010 – 5.75 percent) and GBPC's rate for 2011 was 6.00 percent (2010 – 6.00 percent).

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts. The benefit cost calculations assumed that plan assets would earn a rate of return of 7.00 percent for 2011 (2010 – 7.25 percent) for NSPI and 8.00 percent for 2011 and 2010 for Bangor Hydro. The assumed rate of return on plan assets for 2011 and 2010 was 8.50 percent for MPS and 6.00 percent for 2011 and 2010 for GBPC.

The reported benefit cost for 2011, based on management's best estimate assumptions, is $55.7 million. While there are numerous assumptions which are used to determine the benefit cost, the discount rate and asset return assumptions have an impact on the calculations.

The following shows the impact on 2011 benefit cost of a 25 basis point change (0.25 percent) in the discount rate and asset return assumptions:

	0.25% Increase		0.25% Decrease	
millions of dollars	2011	2010	2011	2010
Discount rate assumption	$(3.9)	$(3.5)	$4.0	$3.6
Asset return assumption	$(2.0)	$(1.8)	$2.0	$1.8

Unbilled Revenue

Electric revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for Bangor Hydro, MPS, BLPC and GBPC. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and of related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses and applicable customer rates. EUS includes an estimate of work completed under contracts but not yet billed at the end of each month. Brunswick Pipeline also makes an estimate of toll revenues at the end of each month. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. As at December 31, 2011, unbilled revenues amount to $133.6 million (2010 – $126.4 million) on a base of annual operating revenues of approximately $2,064.4 million (2010 – $1,606.1 million).

Property, Plant and Equipment

Property, plant and equipment represents 62.0 percent of total assets recognized on the Company's balance sheet. Included in "Property, plant and equipment" are the generation, transmission and distribution and other assets of the Company. Due to the magnitude of the Company's property, plant and equipment, changes in estimated depreciation rates can have a material impact on depreciation expense.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated assets are determined based on formal depreciation studies and require the appropriate regulatory approval.

On May 11, 2011, the UARB approved changes to NSPI's depreciation rates following NSPI's completion of a depreciation study and a settlement agreement with stakeholders. The overall impact on the average deprecation rate is immaterial. The new depreciation rates are effective January 1, 2012, as approved by the UARB in the 2012 General Rate Decision.

Income Taxes

Income taxes are determined based on the expected tax treatment of transactions recorded in the consolidated financial statements. In determining income taxes, tax legislation is interpreted in a variety of jurisdictions, the likelihood that deferred tax assets will be recovered from future taxable income is assessed and assumptions about the expected timing of the reversal of deferred tax assets and liabilities are made. If interpretations differ from those of tax authorities or if the recovery of deferred tax assets or timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. The amount of any such increase or decrease cannot be reasonably estimated.

Asset Retirement Obligations

An asset retirement obligation ("ARO") is recognized if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation using the Company's credit adjusted risk-free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives, and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. Accretion expense is included as part of "Depreciation and amortization". Any accretion expense not yet approved by the regulator is deferred to a regulatory asset in "Property, plant and equipment" and included in the next depreciation study.

Some transmission and distribution assets may have conditional AROs, which are required to be estimated and recorded as a liability. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at fair value when an amount can be determined.

The key assumptions used to determine the ARO are as follows:

Asset	Credit-adjusted risk-free rate		Estimated undiscounted future obligation (millions of dollars)		Expected settlement date (number of years)	
	2011	2010	**2011**	2010	**2011**	2010
Thermal	**5.1 – 5.3%**	5.2 – 5.3%	**$142.8**	$258.9	**21 – 32**	10 – 29
Hydro	**5.1 – 5.3%**	5.2 – 5.3%	**127.6**	101.4	**20 – 50**	21 – 51
Wind	**5.1 – 5.2%**	5.2%	**27.4**	45.5	**17 – 24**	13 – 20
Combustion turbines	**5.1 – 5.3%**	5.2 – 5.3%	**8.3**	12.9	**5 – 34**	1 – 14
Transmission & distribution	**4.3 – 5.8%**	5.7%	**30.4**	21.6	**1 – 14**	1 – 15
Pipeline	**3.50%**	3.80%	**24.6**	11.0	**38**	39
			$361.1	$451.3		

As at December 31, 2011, the AROs recorded on the balance sheet were $99.9 million (2010 – $141.8 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $358.1 million, which will be incurred between 2012 and 2062. The majority of these costs will be incurred between 2032 and 2047.

Goodwill Impairment Assessments

Goodwill represents the excess of the acquisition purchase price for Bangor Hydro, GBPC, ICDU and MAM over the fair values assigned to individual assets acquired and liabilities assumed. Emera is required to perform an impairment assessment annually, or in the interim if an event occurs that indicates the fair value of Bangor Hydro, GBPC, ICDU or MAM may be below its carrying value. Emera performs its annual impairment test as at October 1.

Emera's reporting units will first assess qualitative factors to determine whether it is more likely than not that the assets' fair value is less than the carrying amount, in which case it is necessary to perform the quantitative goodwill impairment test. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. There was no impairment provision required in 2011 or 2010.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Future Accounting Pronouncements

Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, ASU No. 2011-11

In December 2011, The Financial Accounting Standards Board ("FASB") issued an accounting standards update which requires companies to disclose gross information and net information about both instruments and transactions eligible for offset in the statement of financial positions and instruments and transactions subject to an agreement similar to a master netting arrangement to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU No. 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013 with required disclosures made retrospectively for all comparative periods presented. The Company is currently evaluating the impact that the adoption will have in the financial statements.

Other Comprehensive Income, ASU No. 2011-05

In June 2011, FASB issued an accounting standards update amending Accounting Standards Codification ("ASC") 220 to improve the comparability, consistency and transparency of comprehensive income reporting. The guidance requires that items of net income, items of other comprehensive income and total comprehensive income be presented in one continuous statement or two separate but consecutive statements. Items that are reclassified from other comprehensive income to net income must be presented separately on the face of the financial statements. ASU No. 2011-05 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Retrospective application of the new disclosures will be required for comparative periods. The adoption of this update will change the order in which certain consolidated financial statements are presented and provide additional detail on those financial statements where applicable, but will not have any other impact to the consolidated financial statements.

Subsequently in December 2011, FASB issued ASU No. 2011-12, *Deferral of the Effective Date for Amendments to Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05.* The amendments in ASU No. 2011-12 defer the changes in ASU No. 2011-05 that relate to the presentation of reclassification adjustments out of AOCL.

Fair Value Measurement, ASU No. 2011-04

In May 2011, FASB issued an accounting standards update amending ASC 820 to achieve common fair value measurement and disclosure requirements between USGAAP and International Financial Reporting Standards ("IFRS"). The amendments clarify the intent concerning the application of existing requirements and include some instances where a particular principle or requirement for measuring fair value or disclosing information related to fair value measurements has changed. ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The Company is currently evaluating the impact that the adoption will have in the consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q4 2011**	Q3 2011	Q2 2011	Q1 2011	Q4 2010 (adjusted)	Q3 2010 (adjusted)	Q2 2010 (adjusted)	Q1 2010 (adjusted)
Total operating revenues	**$512.0**	$496.1	$501.7	$554.6	$408.9	$394.0	$364.7	$438.5
Net income attributable to common shareholders	**46.8**	40.8	29.9	123.6	24.1	40.3	48.5	77.8
Earnings per common share – basic	**0.38**	0.33	0.24	1.06	0.21	0.35	0.43	0.68
Earnings per common share – diluted	**0.38**	0.33	0.24	1.03	0.21	0.35	0.42	0.67

Quarterly total operating revenues and net income attributable to common shareholders are affected by seasonality. Q1 and Q4 are generally the strongest because a significant portion of the Company's operations are located in northeast North America, where winter is the peak electricity season. Quarterly results are also affected by items outlined in the Significant Items section.

OPERATING STATISTICS (Unaudited)

FIVE-YEAR SUMMARY

Year Ended December 31	**2011**	2010 (adjusted)	2009 (adjusted)	2008 (adjusted)	2007 (adjusted)
Electric energy sales (GWh)					
Residential	**5,458.9**	4,738.2	4,819.2	4,769.6	4,738.5
Commercial	**6,562.3**	5,584.4	3,694.4	3,721.1	3,768.5
Industrial	**3,988.5**	4,268.2	3,985.3	4,491.5	4,568.4
Other	**347.0**	620.1	1,166.9	652.2	655.4
Total electric energy sales	**16,356.7**	15,210.9	13,665.8	13,634.4	13,730.8
Sources of energy (GWh)					
Thermal – coal	**6,848.0**	7,838.7	8,177.3	9,008.9	9,561.4
– oil	**1,070.8**	36.1	306.9	340.7	516.6
– natural gas	**4,304.7**	4,183.0	2,141.4	1,257.9	1,057.1
Hydro	**1,414.5**	991.5	1,063.4	1,065.3	908.8
Wind	**247.0**	25.3	1.8	2.4	2.4
Purchases	**3,518.3**	2,987.4	2,846.1	2,874.5	2,654.7
Total generation and purchases	**17,403.3**	16,062.0	14,536.9	14,549.7	14,701.0
Losses and internal use	**1,046.6**	851.1	871.1	915.3	970.2
Total electric energy sold	**16,356.7**	15,210.9	13,665.8	13,634.4	13,730.8
Electric customers					
Residential	**696,970**	588,935	539,333	535,494	530,955
Commercial	**79,817**	61,620	51,768	54,461	51,083
Industrial	**2,517**	2,558	2,543	2,541	2,543
Other	**10,446**	9,422	9,155	9,064	9,574
Total electric customers	**789,750**	662,535	602,799	601,560	594,155
Capacity					
Generating nameplate capacity (MW)					
Coal fired	**1,243**	1,243	1,243	1,243	1,243
Dual fired	**350**	350	350	365	350
Gas turbines	**666**	599	564	289	304
Hydroelectric	**395**	395	395	395	395
Wind turbines	**82**	76	1	1	1
Diesel	**173**	61	15	15	15
Steam	**47**	51	-	-	-
Independent power producers	**264**	347	172	120	120
	3,220	3,122	2,740	2,428	2,428
Total number of employees	**3,458**	2,972	2,350	2,215	2,194
km of transmission lines	**6,800**	6,700	6,300	6,400	6,100
km of distribution lines	**41,600**	40,900	33,800	32,600	32,000

REGULATED ELECTRIC	Customers	Employee Count	Peak Demand (MW)	Energy Sales (Gwh)	Total Assets (billions)	Rate Base (billions)	Income (millions)	Allowable ROE 2011	Allowable ROE 2010
NSPI	493,183	1,883	2,168	11,206	$3.9	$3.5	$123.5	9.1-9.6%	9.1-9.6%
Bangor Hydro	118,080	295	290.9	1,520.5	0.82	0.50	34.2	11.21%	11.18%
MPS	36,293	127	102.1	496.3	0.14	0.06	2.8	9.69%	9.76%
BLPC	122,900	500	160.1	934.6	0.5	0.3	14.0	10.0%	-
GBPC	19,180	174	64.1	328.3	0.2	-	5.2	-	-

THREE YEAR FINANCIAL SUMMARY

For the year ended December 31 (millions of Canadian dollars)	2011	2010 (adjusted)	2009 (adjusted)
Consolidated Statements of Income			
Operating revenues	**$2,064.4**	$1,606.1	$1,490.1
Operating expenses			
Regulated fuel for generation and purchased power	**866.4**	634.6	550.0
Regulated fuel adjustment	**(8.5)**	(99.0)	8.5
Non-regulated fuel for generation and purchased power	**73.9**	83.9	29.5
Non-regulated direct costs	**60.9**	62.3	37.9
Operating, maintenance and general	**455.0**	351.2	299.1
Provincial, state and municipal taxes	**49.2**	47.4	48.0
Depreciation and amortization	**250.0**	213.5	199.7
Income from operations	**317.5**	312.2	317.4
Income from equity investments and other income (expenses), net	**64.6**	27.8	49.3
Interest expense, net	**159.4**	148.8	132.8
Income before provision for income taxes	**222.7**	191.2	233.9
Income tax expense (recovery)	**(36.7)**	(8.1)	37.4
Net income	**259.4**	199.3	196.5
Non-controlling interest in subsidiaries	**11.7**	5.6	10.2
Net income of Emera Incorporated	**247.7**	193.7	186.3
Preferred stock dividends	**6.6**	3.0	-
Net income attributable to common shares	**241.1**	190.7	186.3
Balance Sheets Information			
Current assets	**993.3**	840.1	811.5
Property, plant and equipment, net of accumulated depreciation	**4,294.4**	3,742.6	3,104.2
Other assets			
Deferred income taxes	**33.1**	31.1	66.2
Derivative instruments	**39.6**	36.0	45.4
Regulatory assets	**312.2**	354.9	278.8
Net investment in direct financing lease	**492.0**	491.5	480.1
Investments subject to significant influence	**222.7**	246.0	216.3
Available-for-sale investments	**54.6**	0.8	1.0
Intangibles, net of accumulated amortization	**100.7**	98.7	93.0
Goodwill	**197.7**	167.4	87.6
Other	**183.3**	69.9	63.2
Total assets	**6,923.6**	6,079.0	5,247.3
Current liabilities	**801.7**	605.9	857.7
Long-term liabilities			
Long-term debt	**3,273.5**	3,115.3	2,272.7
Deferred income taxes	**228.6**	168.5	126.2
Derivative instruments	**38.7**	28.9	35.5
Regulatory liabilities	**107.1**	65.2	91.5
Asset retirement obligations	**99.9**	141.8	104.5
Pension and post-retirement liabilities	**530.8**	400.0	292.4
Other long-term liabilities	**19.6**	22.0	33.0
Equity			
Common stock	**1,385.0**	1,137.8	1,097.9
Preferred stock	**146.7**	146.7	-
Contributed surplus	**3.3**	3.2	3.0
Accumulated other comprehensive loss	**(671.7)**	(564.2)	(426.2)
Retained earnings	**735.9**	653.5	594.8
Total Emera Incorporated equity	**1,599.2**	1,377.0	1,269.5
Non-controlling interest in subsidiaries	**224.5**	154.4	164.3
Total equity	**1,823.7**	1,531.4	1,433.8
Total liabilities and equity	**6,923.6**	6,079.0	5,247.3
Statements of Cash Flow Information			
Cash provided by operating activities	**399.5**	419.2	318.1
Cash used in investing activities	**(660.8)**	(886.0)	(380.8)
Cash provided by financing activities	**331.3**	454.6	61.2
Financial ratios ($ per share)			
Earnings per share	**$1.99**	$1.67	$1.65

EMERA INCORPORATED

Consolidated Financial Statements

December 31, 2011 and 2010

MANAGEMENT REPORT

Management's Responsibility for Financial Reporting

The accompanying consolidated financial statements of Emera Incorporated and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The consolidated financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. In preparation of these consolidated financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management represents that such estimates, which have been properly reflected in the accompanying consolidated financial statements, are based on careful judgements and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the consolidated financial statements.

Emera Incorporated maintains effective systems of internal accounting and administrative controls, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate, and that Emera Incorporated's assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee is appointed by the Board, and its members are directors who are not officers or employees of Emera Incorporated. The Audit Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the consolidated financial statements and the external auditors' report. The Audit Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian Generally Accepted Auditing Standards and the standards of the Public Company Accounting Oversight Board (United States). Ernst & Young LLP has full and free access to the Audit Committee.

February 10, 2012

"Christopher Huskilson"
President and Chief Executive Officer

"Judy Steele, FCA"
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Emera Incorporated

We have audited the accompanying consolidated financial statements of Emera Incorporated, which comprise the consolidated balance sheets as at December 31, 2011 and 2010, and the consolidated statements of income, cash flows, comprehensive income and changes in shareholders' equity, for each of the years in the two-year period ended December 31, 2011, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, 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 Emera Incorporated as at December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2011 in accordance with United States generally accepted accounting principles.

Halifax, Canada
February 10, 2012

"Ernst & Young LLP"
Chartered accountants

Emera Incorporated
Consolidated Statements of Income
Years Ended December 31

millions of Canadian dollars (except per share amounts)	2011	2010 (as adjusted – note 35)
Operating revenues		
Regulated	**$1,891.0**	$1,411.6
Non-regulated	**173.4**	194.5
Total operating revenues	**2,064.4**	1,606.1
Operating expenses		
Regulated fuel for generation and purchased power	**866.4**	634.6
Regulated fuel adjustment (note 5)	**(8.5)**	(99.0)
Non-regulated fuel for generation and purchased power	**73.9**	83.9
Non-regulated direct costs	**60.9**	62.3
Operating, maintenance and general	**455.0**	351.2
Provincial, state, and municipal taxes	**49.2**	47.4
Depreciation and amortization	**250.0**	213.5
Total operating expenses	**1,746.9**	1,293.9
Income from operations	**317.5**	312.2
Income from equity investments (note 15)	**21.5**	15.3
Other income (expenses), net (note 6)	**43.1**	12.5
Interest expense, net (note 7)	**159.4**	148.8
Income before provision for income taxes	**222.7**	191.2
Income tax expense (recovery) (note 8)	**(36.7)**	(8.1)
Net income	**259.4**	199.3
Non-controlling interest in subsidiaries	**11.7**	5.6
Net income of Emera Incorporated	**247.7**	193.7
Preferred stock dividends	**6.6**	3.0
Net income attributable to common shareholders	**$241.1**	$190.7
Weighted average shares of common stock outstanding (in millions)		
Basic	**121.0**	114.2
Diluted	**126.2**	120.4
Earnings per common share (note 9)		
Basic	**$1.99**	$1.67
Diluted	**$1.97**	$1.65
Dividends per common share declared	**$1.3125**	$1.1625

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Consolidated Balance Sheets
As at December 31

millions of Canadian dollars	**2011**	2010 (as adjusted – note 35)
Assets		
Current assets		
Cash and cash equivalents	**$76.9**	$7.3
Restricted cash (note 10)	**14.0**	58.6
Receivables, net (note 11)	**459.6**	392.9
Income taxes receivable	**41.6**	37.0
Inventory (note 12)	**198.8**	177.8
Deferred income taxes (note 8)	**14.0**	13.7
Derivative instruments (note 24)	**27.3**	49.7
Regulatory assets (note 23)	**141.6**	90.5
Prepaid expenses	**15.1**	9.5
Other current assets	**4.4**	3.1
Total current assets	**993.3**	840.1
Property, plant and equipment, net of accumulated depreciation of $2,838.0 and $2,462.6, respectively (note 13)	**4,294.4**	3,742.6
Other assets		
Deferred income taxes (note 8)	**33.1**	31.1
Derivative instruments (note 24)	**39.6**	36.0
Regulatory assets (note 23)	**312.2**	354.9
Net investment in direct financing lease (note 14)	**492.0**	491.5
Investments subject to significant influence (note 15)	**222.7**	246.0
Available-for-sale investments (note 16)	**54.6**	0.8
Goodwill (note 17)	**197.7**	167.4
Intangibles, net of accumulated amortization of $59.7 and $40.2 respectively	**100.7**	98.7
Other	**183.3**	69.9
Total other assets	**1,635.9**	1,496.3
Total assets	**$6,923.6**	$6,079.0

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Consolidated Balance Sheets – Continued
As at December 31

millions of Canadian dollars	2011	2010 (as adjusted – note 35)
Liabilities and Equity		
Current liabilities		
Short-term debt (note 19)	**$210.3**	$81.7
Current portion of long-term debt (note 20)	**35.7**	10.6
Accounts payable	**332.9**	293.9
Income taxes payable	**1.9**	0.2
Deferred income taxes (note 8)	**10.9**	8.5
Derivative instruments (note 24)	**50.1**	36.8
Regulatory liabilities (note 23)	**23.9**	55.0
Pension and post-retirement liabilities (note 26)	**8.8**	8.9
Other current liabilities (note 21)	**127.2**	110.3
Total current liabilities	**801.7**	605.9
Long-term liabilities		
Long-term debt (note 20)	**3,273.5**	3,115.3
Deferred income taxes (note 8)	**228.6**	168.5
Derivative instruments (note 24)	**38.7**	28.9
Regulatory liabilities (note 23)	**107.1**	65.2
Asset retirement obligations (note 22)	**99.9**	141.8
Pension and post-retirement liabilities (note 26)	**530.8**	400.0
Other long-term liabilities	**19.6**	22.0
Total long-term liabilities	**4,298.2**	3,941.7
Commitments and contingencies (note 27)		
Equity		
Common stock, no par value; unlimited shares authorized; 122.83 million shares and 114.62 million shares issued and outstanding, respectively (note 28)	**1,385.0**	1,137.8
Cumulative preferred stock Series A, par value $25 per share; unlimited shares authorized; 6 million shares issued and outstanding (note 30)	**146.7**	146.7
Contributed surplus	**3.3**	3.2
Accumulated other comprehensive loss (note 31)	**(671.7)**	(564.2)
Retained earnings	**735.9**	653.5
Total Emera Incorporated equity	**1,599.2**	1,377.0
Non-controlling interest in subsidiaries	**224.5**	154.4
Total equity	**1,823.7**	1,531.4
Total liabilities and equity	**$6,923.6**	$6,079.0

The accompanying notes are an integral part of these consolidated financial statements

Approved on behalf of the Board of Directors

"John T. McLennan" ***"Christopher G. Huskilson"***

Chairman **President and Chief Executive Officer**

Emera Incorporated Consolidated Statements of Cash Flows
Years Ended December 31

millions of Canadian dollars	2011	2010 (as adjusted – note 35)
Operating activities		
Net income	**$259.4**	$199.3
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**263.2**	231.6
Income from equity investments, net of dividends	**(0.9)**	9.5
Allowance for equity funds used during construction	**(13.1)**	(11.8)
Deferred income taxes, net	**11.6**	39.1
Net change in pension and post-retirement obligations	**(8.1)**	(15.5)
Regulated fuel adjustment	**(15.2)**	(102.8)
Net changes in fair value of derivative instruments	**6.6**	(0.7)
Net change in regulatory assets and liabilities	**(13.4)**	(30.7)
Other operating activities, net	**(50.3)**	18.5
Changes in non-cash working capital		
Receivables, net	**(45.0)**	39.5
Income taxes receivable	**(4.2)**	(32.7)
Inventory	**(3.9)**	13.6
Prepaid expenses	**(1.2)**	(2.3)
Other current assets	**0.1**	1.5
Accounts payable	**2.1**	53.4
Income taxes payable	**1.5**	(2.6)
Other current liabilities	**10.3**	12.3
Net cash provided by operating activities	**399.5**	419.2
Investing activities		
Additions to property, plant and equipment	**(472.1)**	(525.5)
Acquisition, net of cash acquired	**(41.9)**	(157.7)
Decrease in restricted cash	**57.9**	(58.4)
Purchase of investments subject to significant influence, inclusive of acquisition costs (note 15)	**(33.8)**	(88.4)
Allowance for borrowed funds used during construction	**(10.9)**	(10.5)
Retirement spending, net of salvage	**(16.8)**	(16.3)
Purchase of subscription receipts	**(136.0)**	-
Other investing activities	**(7.2)**	(29.2)
Net cash used in investing activities	**(660.8)**	(886.0)
Financing activities		
Change in short-term debt, net	**133.0**	(24.1)
Retirement of long-term debt	**(13.4)**	(346.8)
Proceeds from long-term debt	**251.8**	542.3
Net repayments under committed credit facilities	**(119.6)**	258.9
Issuance of common stock, net of issuance costs	**244.0**	39.5
Issuance of preferred stock	**-**	145.2
Dividends on common stock	**(157.6)**	(132.0)
Dividends on preferred stock	**(6.6)**	(3.0)
Dividends paid by subsidiaries to non-controlling interest	**(8.7)**	(7.9)
Other financing activities	**8.5**	(17.5)
Net cash provided by financing activities	**331.4**	454.6
Effect of exchange rate changes on cash and cash equivalents	**(0.5)**	(0.7)
Net increase (decrease) in cash and cash equivalents	**69.6**	(12.9)
Cash and cash equivalents, beginning of period	**7.3**	20.2
Cash and cash equivalents, end of period	**$76.9**	$7.3
Cash and cash equivalents consists of:		
Cash	**$59.2**	$7.3
Short-term investments	**17.7**	-
Cash and cash equivalents	**$76.9**	7.3
Supplemental disclosure of cash paid (received):		
Interest	**$170.4**	$149.7
Income and capital taxes	**$(33.0)**	$(2.1)

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Consolidated Statements of Comprehensive Income (note 31)
Years Ended December 31

millions of Canadian dollars	**2011**	2010 (as adjusted – note 35)
Net income attributable to common shareholders	**$241.1**	190.7
Other comprehensive income (loss), net of tax		
Unrealized losses on cash flow hedges (1)	**(10.8)**	(0.5)
Hedging losses included in income (2)	**2.1**	6.6
Net change in unrecognized pension and post-retirement benefit costs (3)	**(122.9)**	(113.4)
Unrealized loss on available-for-sale investment	**(0.3)**	(0.2)
Unrealized gain (loss) on translation of self-sustaining foreign operations (4)	**24.4**	(30.5)
Other comprehensive loss, net of tax (5)	**(107.5)**	(138.0)
Comprehensive income attributable to common shareholders	**$133.6**	$52.7

The accompanying notes are an integral part of these consolidated financial statements.

1) Net of tax recovery of $7.8 million (2010 - $4.8 million tax recovery) for the year ended December 31, 2011.
2) Net of tax expense of $3.2 million (2010 - $4.6 million tax expense) for the year ended December 31, 2011.
3) Net of tax recovery of $8.4 million (2010 - $2.6 million tax recovery) for the year ended December 31, 2011.
4) Net of tax expense of $0.1 million (2010 - nil) for the year ended December 31, 2011.
5) Net of tax recovery of $12.9 million (2010 - $2.8 million tax recovery) for the year ended December 31, 2011.

Emera Incorporated
Consolidated Statements of Changes in Equity
Years Ended December 31

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Loss ("AOCL")	Retained Earnings	Non-Controlling Interest	Total Equity
2011							
Balance, December 31, 2010 (as adjusted – note 35)	$1,137.8	$146.7	$3.2	$(564.2)	$653.5	$154.4	$1,531.4
Net income of Emera Incorporated	-	-	-	-	247.7	11.7	259.4
Other comprehensive loss, net of tax recovery of $12.9	-	-	-	(107.5)	-	-	(107.5)
Issuance of common stock, net of issuance costs	196.0	-	-	-	-	-	196.0
Additional investments	-	-	-	-	-	67.1	67.1
Cash dividends declared on preferred stock ($1.1000/share)	-	-	-	-	(6.6)	-	(6.6)
Cash dividends declared on common stock ($1.3125/share)	-	-	-	-	(158.7)	-	(158.7)
Dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	(0.7)	(0.7)
Common stock issued under purchase plan	41.0	-	-	-	-	-	41.0
Senior management stock options exercised	8.8	-	(0.6)	-	-	-	8.2
Stock option expense	-	-	0.7	-	-	-	0.7
Other stock-based compensation	1.4	-	-	-	-	-	1.4
Preferred dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	(8.0)	(8.0)
Balance, December 31, 2011	$1,385.0	$146.7	$3.3	$(671.7)	$735.9	$224.5	$1,823.7
2010 (as adjusted – note 35)							
Balance, December 31, 2009	$1,097.9	-	$3.0	$(426.2)	$594.8	$164.3	$1,433.8
Net income of Emera Incorporated	-	-	-	-	193.7	5.6	199.3
Other comprehensive loss, net of tax recovery of $2.8	-	-	-	(138.0)	-	-	(138.0)
Additional investment	-	-	-	-	-	(5.5)	(5.5)
Cash dividends declared on preferred stock ($0.4980/share)	-	-	-	-	(3.0)	-	(3.0)
Cash dividends declared on common stock ($1.1625/share)	-	-	-	-	(132.0)	-	(132.0)
Common stock issued under purchase plan	32.9	-	-	-	-	-	32.9
Senior management stock options exercised	6.0	-	(0.5)	-	-	-	5.5
Stock option expense	-	-	0.7	-	-	-	0.7
Other stock-based compensation	1.0	-	-	-	-	-	1.0
Issuance of preferred shares	-	146.7	-	-	-	-	146.7
Preferred dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	(8.0)	(8.0)
Other	-	-	-	-	-	(2.0)	(2.0)
Balance, December, 2010	$1,137.8	$146.7	$3.2	$(564.2)	$653.5	$154.4	$1,531.4

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Notes to the Consolidated Financial Statements

As at December 31, 2011 and 2010

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies for both the regulated and non-regulated operations of Emera Incorporated are as follows:

A. Nature of Operations

Emera Incorporated is an energy and services company which invests in electricity generation, transmission and distribution, gas transmission and utility energy services.

Emera's primary rate-regulated subsidiaries at December 31, 2011 include the following:

- Nova Scotia Power Inc. ("NSPI"), a fully-integrated electric utility and the primary electricity supplier in Nova Scotia serving approximately 493,000 customers;
- Bangor Hydro Electric Company ("Bangor Hydro") and Maine Public Service Company ("MPS"), (a wholly-owned subsidiary of Maine and Maritimes Corporation ("MAM")), which together provide transmission and distribution services to approximately 154,000 customers in Maine;
- an 80.1 percent interest in Light & Power Holdings Ltd. ("LPH"), the parent of The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated utility and sole provider of electricity on the island of Barbados serving approximately 123,000 customers;
- a 50.0 percent direct and 30.4 percent indirect interest (through ICD Utilities Limited ("ICDU")) in Grand Bahama Power Company Limited ("GBPC"), a vertically-integrated utility and sole provider of electricity on Grand Bahama Island serving approximately 19,000 customers; and
- Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145 kilometer pipeline carrying re-gasified liquefied natural gas from Saint John, New Brunswick to the United States border under a 25 year firm service agreement with Repsol Energy Canada ("REC").

Emera Incorporated and its subsidiaries ("Emera" or the "Company") also own investments in other non rate-regulated energy related companies, including:

- Emera Energy Services, a physical energy business which purchases and sells natural gas and electricity and provides related energy asset management services;
- Bayside Power Limited Partnership ("Bayside Power"), a 260-megawatt ("MW") electricity generating facility in Saint John, New Brunswick ;
- Emera Utility Services Inc. ("EUS"), a utility services contractor;
- a 50 percent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 600-MW pumped storage hydro-electric facility in northern Massachusetts;
- Emera Newfoundland & Labrador Holdings Inc. ("ENL"), a development project focused on transmission investments related to the proposed 824-MW hydro-electric generating facility at Muskrat Falls in Labrador, scheduled to be in service in 2017;
- a 12.9 percent interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400 kilometer pipeline which transports natural gas from offshore Nova Scotia to markets in Maritime Canada and the northeastern United States;
- a 19.1 percent interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically-integrated regulated electric utility on the Caribbean island of St. Lucia;
- a 49.999 percent interest in California Pacific Utilities Ventures, LLC, ("CPUV");
- a 6.3 percent investment in Algonquin Power & Utilities Corp ("APUC");
- a 37.7 percent investment in Atlantic Hydrogen Inc. ("AHI"); and
- other investments.

B. Basis of Presentation

Effective January 1, 2011, Emera changed the basis of presentation of its financial statements (including the application of rate-regulated accounting policies for Emera's rate-regulated subsidiaries) from Canadian Generally Accepted Accounting Principles ("CGAAP") to United States Generally Accepted Accounting Principles ("USGAAP").

These consolidated financial statements are prepared and presented in accordance with USGAAP and the rules and regulations of the United States Securities and Exchange Commission ("SEC") for Annual Reports filed under the Multi-Jurisdictional Disclosure System. These consolidated financial statements should be read in conjunction with note 35, detailing the CGAAP to USGAAP transition and reconciliation information.

In the opinion of management, these consolidated financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera Incorporated.

All dollar amounts are presented in Canadian dollars, unless otherwise indicated.

C. Principles of Consolidation

The consolidated financial statements of Emera Incorporated include the accounts of Emera Incorporated and its majority-owned subsidiaries, and a variable interest entity where Emera is the primary beneficiary. All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes that the elimination of these transactions would understate property, plant and equipment, operating, maintenance and general expenses, or regulated fuel for generation and purchased power.

Where Emera does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. The cost method of accounting is used for investments where Emera does not have significant influence over the operating and financial policies of the investee.

D. Use of Management Estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an on-going basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. Significant estimates are included in unbilled revenue, allowance for doubtful accounts, inventory, valuation of derivative instruments, depreciation, amortization, regulatory assets and regulatory liabilities (including the determination of the current portion), income taxes (including deferred income taxes), pension and post-retirement benefits, asset retirement obligations ("AROs") and contingencies. Actual results may differ significantly from these estimates.

E. Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third party regulator; are designed to recover the costs of providing the regulated products or services; and it is reasonable to assume rates are set at levels such that the costs can be charged to and collected from customers.

Regulatory assets represent incurred costs that have been deferred because it is probable that they will be recovered through future rates or tolls collected from customers. Management believes that existing regulatory assets are probable of recovery either because the Company received specific approval from the appropriate regulator, or due to regulatory precedent set for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income. Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

For regulatory assets and liabilities that are amortized, the amortization is as approved by the respective regulator.

F. Foreign Currency Translation

Monetary assets and liabilities, denominated in foreign currencies, are converted to Canadian dollars at rates of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date are included in income.

Assets and liabilities of self-sustaining foreign operations are translated using the exchange rates in effect at the balance sheet date and the results of operations at the average rates for the period. The resulting exchange gains and losses on the assets and liabilities are deferred on the balance sheet in AOCL.

G. Revenue Recognition

Operating revenues are recognized when electricity is delivered to customers or when products are delivered and services are rendered. Revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity are recognized at rates approved by the respective regulator and recorded based on meter readings and estimates, which occur on a systematic basis throughout a month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The accuracy of the unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

The Company records the net investment in a lease under the direct finance method, which consists of the sum of the minimum lease payments and residual value net of estimated executory costs and unearned income. The difference between the gross investment and the cost of the leased item for a direct financing lease is recorded as unearned income at the inception of the lease. The unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.

Other revenues are recognized when services are performed or goods delivered.

H. Research and Development Costs

Research and development costs are expensed as incurred.

I. Stock-Based Compensation

The Company has several stock-based compensation plans: a common share option plan for senior management; an employee common share purchase plan; a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. The Company accounts for its plans in accordance with the fair value based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee's or director's requisite service period using the graded vesting method. Stock-based compensation plans recognized as liabilities are measured at fair value and re-measured at fair value at each reporting date with the change in liability recognized as expense.

J. Employee Benefits

The costs of the Company's pension and other post-employment benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-employment plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in AOCL.

K. Earnings per Share

Basic earnings per share ("EPS") is determined by dividing net income attributable to common shareholders by the weighted average number of common shares and DSUs outstanding during the period. Diluted EPS is computed by dividing net income attributable to common shareholders by the weighted average number of common shares and DSUs outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include Company contributions to the employee common share purchase plan, PSUs and the senior management stock option plan.

L. Cash and Cash Equivalents

Cash equivalents consist of highly liquid short-term investments with original maturities of three months or less at acquisition. The short-term investments of $17.7 million have an effective interest rate of 3.4 percent at December 31, 2011 (2010 – nil short-term investments).

M. Receivables and Allowance for Doubtful Accounts

Customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity sales are approximately 30 days. A late payment fee may be assessed on account balances after the due date.

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit risk assessments are conducted on all new customers and deposits are requested on any high risk accounts. The Company also maintains provisions for potential credit losses, which are assessed on a regular basis.

Management estimates uncollectible accounts receivable after considering historical loss experience, current events and the characteristics of existing accounts. Provisions for losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

N. Inventory

Inventory, consisting of fuel and materials, is measured at the lower of cost or market. Fuel cost is determined using the weighted average method and material cost is determined using the average costing method. Fuel and materials are charged to inventory when purchased and then expensed or capitalized, as appropriate, using the weighted average cost method for fuel and average costing method for materials.

O. Property, Plant and Equipment

Property, plant and equipment are recorded at original cost, including allowance for funds used during construction ("AFUDC") or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units of property plant and equipment are included in "Property, plant and equipment". When units of regulated property, plant and equipment are replaced, renewed or retired, their cost plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation with no gain or loss reflected in income. Where a disposition of non-regulated property, plant and equipment occurs, gains and losses are included in income as the dispositions occur.

Normal maintenance projects are expensed as incurred. Planned major maintenance projects that do not increase the overall life of the related assets are expensed. When a cost increases the life or value of the underlying asset, the cost is capitalized.

P. Capitalization Policy

The cost of property, plant, and equipment represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, AROs and overhead directly attributable to the capital project. Overhead includes corporate costs such as finance, information technology and executive, along with other costs related to support functions, employee benefits, insurance, inventory, and fleet operating and maintenance.

Q. Allowance for Funds Used During Construction

AFUDC represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment. As approved by their respective regulator, NSPI, Bangor Hydro, MPS, GBPC, and Brunswick Pipeline include an equity cost component in AFUDC in addition to a charge for borrowed funds. AFUDC is a non-cash item; cash is realized under the rate-making process over the service life of the related property, plant and equipment through future revenues resulting from a higher rate base and recovery of higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to “Interest expense, net”, while the equity component is included in “Other income (expenses), net”. AFUDC is calculated using a weighted average cost of capital, as per the method of calculation approved by the respective regulator, and is compounded semi-annually. The annual AFUDC consisted of the following:

			2011			2010
	Total	**Debt Component**	**Equity Component**	Total	Debt Component	Equity Component
NSPI	**7.87%**	**4.06%**	**3.81%**	7.96%	4.15%	3.81%
Bangor Hydro	**9.00%**	**2.60%**	**6.40%**	8.59%	2.66%	5.93%
MPS	**8.89%**	**2.40%**	**6.49%**	N/A	N/A	N/A
GBPC	**10.00%**	**4.40%**	**5.60%**	N/A	N/A	N/A

R. Depreciation

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets, including assets under capital leases, in each category. The service lives of regulated assets are determined based on formal depreciation studies and require the appropriate regulatory approval.

The estimated useful lives, in years, for each major category of property, plant and equipment consist of the following:

Generation	15 to 131
Transmission	10 to 83
Distribution	11 to 75
General plant	5 to 53

S. Intangible Assets

Intangible assets consist primarily of land rights and computer software with definite lives. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated assets are determined based on formal depreciation studies and require the appropriate regulatory approval. Intangible assets with indefinite lives are not amortized but tested for impairment at least annually.

The estimated useful lives, in years, for each major category of intangibles with definite lives consist of the following:

Land rights	50 to 143
Computer software	3 to 10

The estimated aggregate amortization expense for each of the five succeeding fiscal years is as follows:

millions of Canadian dollars	2012	2013	2014	2015	2016
Land rights	$1.1	$1.1	$1.1	$1.1	$1.1
Computer software	7.0	6.9	5.1	5.1	4.7
	$8.1	$8.0	$6.2	$6.2	$5.8

T. Asset Impairment

Goodwill

Goodwill is subject to an annual impairment test. Emera has early adopted Accounting Standards Update ("ASU") Number ("No.") 2011-08, "Intangibles – Goodwill and Other". This new approach was used in the annual impairment test on October 1 (refer to Note 2), or when events or circumstances indicate that an asset may be impaired. In line with this standard, Emera's reporting units will first assess qualitative factors to determine whether it is more likely than not that the assets' fair value is less than the carrying amount, in which case it is necessary to perform the quantitative goodwill impairment test. The carrying amount of the reporting unit's goodwill may not be recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value.

Long-Lived Assets

Other long-lived assets require an impairment review when events or circumstances indicate that the carrying amount may not be recoverable. Emera bases its evaluation of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements, and other external market conditions or factors.

Assets Held and Used: The carrying amount of assets held and used is considered not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value.

Assets Held for Sale: The carrying value of assets held for sale is considered not recoverable if it exceeds the fair value less the cost to sell. An impairment charge is recorded for any excess of the carrying value over the fair value less estimated costs to sell.

Cost and Equity Method Investments

The carrying value of investments accounted for under the cost and equity methods are assessed for impairment by comparing the fair values of these investments to their carrying values, if a fair value assessment was completed; or by reviewing for the presence of impairment indicators. If an impairment exists and it is determined to be other-than-temporary, a charge is recognized equal to the amount the carrying value exceeds the investment's fair value.

Financial Assets

The Company assesses at each balance sheet date whether there is objective evidence that a financial asset or a group of financial assets is impaired. In the case of equity securities classified as available-for-sale, a significant or prolonged decline in the fair value of the security below its cost is considered as an indicator that the securities are impaired. In the case of debt securities classified as available-for-sale, a breach of contract such as default or delinquency in interest or principal payments, or evidence of significant financial difficulty of the issuer is considered an indicator of impairment. If any such evidence exists for available-for-sale financial assets, the cumulative loss, measured as the difference between the acquisition cost and the current fair value, less any impairment loss on that financial asset previously recognized in income, is removed from AOCL and recognized on the Consolidated Statements of Income.

There were no material asset impairments for the years ended December 31, 2011 and 2010.

U. Debt Financing Costs

The Company capitalizes the external costs of obtaining debt financing and includes them in “Other” as part of “Other assets” on the Consolidated Balance Sheet; premiums and discounts are netted against “Long-term debt” on the Consolidated Balance Sheet. The deferred charges are amortized over the life of the related debt on an effective interest basis and included in “Interest expense, net”.

V. Income Taxes and Investment Tax Credits

Emera recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheet and their respective tax bases using enacted tax rates in effect for the year in which the differences are expected to reverse. Emera recognizes the effect of income tax positions only when it is more likely than not that they will be realized. If management subsequently determines that it is likely that some or all of a deferred income tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

Generally, investment tax credits are recorded as a reduction to income tax expense in the current or future periods to the extent that realization of such benefit is more likely than not. Investment tax credits earned by Bangor Hydro or MPS on regulated assets are deferred and amortized over the estimated service lives of the related properties, as required by United State tax laws and Maine regulatory practices.

Emera classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively.

W. Asset Retirement Obligations

An ARO is recognized if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation using the Company’s credit adjusted risk-free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives, and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. Accretion expense is included as part of “Depreciation and amortization”. Any accretion expense not yet approved by the regulator is deferred to a regulatory asset in “Property, plant and equipment” and included in the next depreciation study.

Some transmission and distribution assets may have conditional AROs, which are required to be estimated and recorded as a liability. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at fair value when an amount can be determined.

X. Derivatives and Hedging Activities

Emera's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management practices are overseen by the Board of Directors. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operations.

The Company manages its exposure to normal operating and market risks relating to commodity prices, foreign exchange and interest rates using financial instruments consisting mainly of foreign exchange forwards and swaps, interest rate options and swaps, and coal, oil and gas futures, options, forwards, and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. Collectively these contracts are considered "derivatives".

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exception. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty credit worthy. Emera continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exception where the criteria are no longer met.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and can be proven to effectively hedge the identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to AOCL and recognized in income in the same period the related hedged item is realized. Any ineffective portion of the change in the fair value of the cash flow hedges is recognized in net income in the reporting period.

Where the documentation or effectiveness requirements are not met, the derivatives are recognized at fair value, with any changes in fair value recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

Derivatives entered into by NSPI that are documented as economic hedges, and for which the NPNS exception has not been taken, receive regulatory deferral as approved by the Nova Scotia Utility and Review Board ("UARB"). These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized when the derivatives settle. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates through the FAM.

Derivatives that do not meet any of the above criteria are designated as HFT derivatives and are recorded on the balance sheet at fair value, with changes normally recorded in net income of the period, unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

Emera classifies gains and losses on derivatives as a component of fuel for generation and purchased power, other expenses, inventory and property, plant and equipment, depending on the nature of the item being economically hedged. Cash flows from derivative activities are presented in the same category as the item being hedged within operating or investing activities on the Consolidated Statements of Cash Flows.

Y. Fair Value Measurement

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exception (refer to notes 24 and 25). Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arms-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information including the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. The Company uses a fair value hierarchy, based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the highest.

The three levels of the fair value hierarchy are defined as follows:

Level 1 Valuations - Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 Valuations - Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 Valuations - Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally-developed inputs. Emera's primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Z. Variable Interest Entities

The Company performs ongoing analysis to assess whether it holds any variable interest entities ("VIEs"). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where Emera is not deemed the primary beneficiary, the VIE is not recorded in the Company's consolidated financial statements.

LPH has established a self-insurance fund ("SIF") primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. LPH holds a variable interest in the SIF for which it was determined that LPH was the primary beneficiary and, accordingly, the SIF must be consolidated by LPH. In its determination that LPH controls the SIF, management considered that in substance the activities of the SIF are being conducted on behalf of LPH's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because LPH, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF.

NSPI holds a variable interest in Renewable Energy Services Ltd. ("RESL"), a VIE for which it was determined that NSPI was not the primary beneficiary since it does not have the controlling financial interest of RESL. NSPI has provided a $23.5 million guarantee with no set term for the indebtedness of RESL under a loan agreement between RESL and a third party lender, in support of which NSPI holds a security interest in all present and future assets of RESL. The guarantee arose in conjunction with NSPI's participation in a wind energy project at Point Tupper, Nova Scotia, which is being operated by RESL. Under a purchased power agreement, NSPI purchases, at a fixed price, 100 percent of the power generated by the project. A default by RESL, under its loan agreement, would require NSPI to make payment under the guarantee. As at December 31, 2011, RESL's indebtedness under the loan agreement was $21.9 million (2010 – $23.1 million), and NSPI has not recorded a liability in relation to the guarantee.

Bangor Hydro holds a variable interest in Chester Static Var Compensator ("SVC"), a VIE for which it was determined that Bangor Hydro was not the primary beneficiary since it does not have the controlling financial interest of Chester SVC. A subsidiary of Bangor Hydro is a 50 percent general partner in Chester SVC, which owns electrical equipment that supports a major transmission line. A wholly-owned subsidiary of Central Maine Power Company owns the other 50 percent interest. Chester SVC is 100 percent debt financed and accordingly the partners have no equity interest; and the holders of the SVC notes are without recourse against the partners or their parent companies.

The Company has identified certain long-term purchase power agreements that could be defined as variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

Emera's consolidated VIE is recorded as an "Available-for-sale investment". The following table provides information about Emera's consolidated and unconsolidated VIEs as at December 31:

millions of Canadian dollars		**2011**		2010
	Total assets	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Consolidated VIE				
BLPC SIF Available-for-sale investment	**$54.1**	**$54.1**	-	-
Unconsolidated VIEs in which Emera has Variable Interests				
RESL	**-**	**23.5**	-	$23.5
Chester SVC	**-**	**-**	-	-

AA. Available-for-sale Investments

Assets designated as Available-for-sale are non-derivative financial assets (equity and debt securities) intended to be held for an indefinite period of time, and may be sold in response to needs for liquidity or changes in interest rates, exchange rates or equity prices.

Regular purchases and sales of financial assets are recognized at fair value, including transaction costs, on the trade date, the date on which the Company commits to purchase or sell the asset; and subsequently carried at fair value based on current bid prices on the market. Unrealized gain and losses arising from changes in the fair value of available-for-sale assets are recognized in AOCL until the financial asset is sold, or otherwise disposed of, or until the financial investment is determined to be impaired, at which time the cumulative gain or loss will be included in income for the period.

Interest on available-for-sale debt securities is calculated using the effective interest method and is recognized on the Consolidated Statements of Income in "Other income (expenses), net". Dividends on available-for-sale equity securities are recognized on the Consolidated Statements of Income in "Other income (expenses), net".

BB. Derivative Positions and Cash Collateral

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in "Receivables, net" and obligations to return cash collateral are recognized in "Accounts payable".

2. CHANGE IN ACCOUNTING POLICY

In Q1 2011, the Company changed the date of its annual impairment test from March 31 to October 1. The change was made to more closely align the impairment testing date with the long-range planning and forecasting process. Emera believes the change in the annual impairment testing date did not delay, accelerate, or avoid an impairment charge and has determined this change in accounting policy is preferable under the circumstances and does not result in adjustments to the financial statements when applied retrospectively.

In Q4 2011, Emera early adopted ASU No. 2011-08, "Intangibles – Goodwill and Other". This new approach was used in its annual impairment test on October 1, 2011.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, ASU No. 2011-11

In December 2011, The Financial Accounting Standards Board ("FASB") issued an accounting standards update which requires companies to disclose gross information and net information about both instruments and transactions eligible for offset in the statement of financial positions and instruments and transactions subject to an agreement similar to a master netting arrangement to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU No. 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013 with required disclosures made retrospectively for all comparative periods presented. The Company is currently evaluating the impact that the adoption will have in the financial statements.

Other Comprehensive Income, ASU No. 2011-05

In June 2011, FASB issued an accounting standards update amending Accounting Standards Codification ("ASC") 220 to improve the comparability, consistency and transparency of comprehensive income reporting. The guidance requires that items of net income, items of other comprehensive income and total comprehensive income be presented in one continuous statement or two separate but consecutive statements. Items that are reclassified from other comprehensive income to net income must be presented separately on the face of the financial statements. ASU No. 2011-05 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Retrospective application of the new disclosures will be required for comparative periods. The adoption of this update will change the order in which certain consolidated financial statements are presented and provide additional detail on those financial statements where applicable, but will not have any other impact to the consolidated financial statements.

Subsequently in December 2011, FASB issued ASU No. 2011-12, *Deferral of the Effective Date for Amendments to Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05.* The amendments in ASU No. 2011-12 defer the changes in ASU No. 2011-05 that relate to the presentation of reclassification adjustments out of AOCL.

Fair Value Measurement, ASU No. 2011-04

In May 2011, FASB issued an accounting standards update amending ASC 820 to achieve common fair value measurement and disclosure requirements between USGAAP and International Financial Reporting Standards ("IFRS"). The amendments clarify the intent concerning the application of existing requirements and include some instances where a particular principle or requirement for measuring fair value or disclosing information related to fair value measurements has changed. ASU No. 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The Company is currently evaluating the impact that the adoption will have in the consolidated financial statements.

4. SEGMENT INFORMATION

Emera is an energy and services company which invests in electricity generation, transmission and distribution, gas transmission and utility energy services. Emera manages its reportable segments separately due to their different geographical, operating and regulatory environments. Segments are reported based on each subsidiary's contribution of revenues, net income and total assets.

As at December 31, 2011, Emera has five reporting segments, specifically:

- NSPI;
- Maine Utility Operations (Bangor Hydro and MPS);
- Caribbean Utility Operations (BLPC, GBPC and Lucelec);
- Brunswick Pipeline; and
- Other (Emera Energy Services, EUS, M&NP, other strategic investments, holding companies, and inter-segment eliminations).

Bangor Hydro and MPS have been combined into Maine Utility Operations as the companies have similar geographical, operating, and regulatory environments. In Q4 2010, MPS was reported in "Other". BLPC, GBPC and Lucelec have been combined into Caribbean Utility Operations as the companies have similar regulated operations including generation, transmission and distribution. In Q4 2010, the Company reported Caribbean Utility Operations in "Other" as Emera's investment in these entities was not substantial enough to meet segment reporting requirements. Prior periods have been restated to reflect the Maine Utility and Caribbean Utility Operations as segments.

millions of Canadian dollars	NSPI	Maine Utility Operations	Caribbean Utility Operations	Brunswick Pipeline	Other and Eliminations	Total
Year ended December 31, 2011						
Operating revenues from external customers (1)	$1,232.5	$202.4	$406.3	$49.7	$148.9	$2,039.8
Inter-segment revenues (1)	0.5	-	-	-	24.1	24.6
Total operating revenues	1,233.0	202.4	406.3	49.7	173.0	2,064.4
Allowance for funds used during construction – debt and equity	16.2	6.1	1.5	-	0.2	24.0
Regulated fuel adjustment	(8.5)	-	-	-	-	(8.5)
Depreciation and amortization	187.2	36.5	22.6	0.1	3.6	250.0
Interest expense	122.6	14.0	9.2	-	34.7	180.5
Interest revenue	10.0	0.5	-	-	(0.3)	10.2
Internally allocated interest (2)	-	-	-	(30.2)	30.2	-
Gain on acquisition	-	-	-	-	28.2	28.2
Income from equity investments	-	-	2.8	-	18.7	21.5
Income tax expense (recovery)	(44.9)	22.4	0.7	-	(14.9)	(36.7)
Capital expenditures	307.9	91.9	69.6	0.2	25.4	495.0
Net income attributable to common shareholders	123.5	37.0	46.8	19.7	14.1	241.1
As at December 31, 2011						
Total assets	3,897.0	963.0	848.8	545.8	669.0	6,923.6
Investments subject to significant influence	-	1.2	26.7	-	194.8	222.7
Goodwill	-	116.4	77.5	-	3.8	197.7

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes that the elimination of these transactions would understate property, plant and equipment, operating, maintenance and general expenses, or regulated fuel for generation and purchased power. Eliminated transactions are included in determining reportable segments.

(2) Segment net income is reported on a basis that includes internally allocated financing costs.

millions of Canadian dollars	NSPI	Maine Utility Operations	Caribbean Utility Operations	Brunswick Pipeline	Other and Eliminations	Total
Year ended December 31, 2010						
Operating revenues from external customers (1)	$1,190.2	$172.4	-	$48.9	$171.0	$1,582.5
Inter-segment revenues (1)	1.2	-	-	-	22.4	23.6
Total operating revenues	1,191.4	172.4	-	48.9	193.4	1,606.1
Allowance for funds used during construction – debt and equity	17.2	5.1	-	-	-	22.3
Regulated fuel adjustment	(99.0)	-	-	-	-	(99.0)
Depreciation and amortization	188.1	21.5	-	0.1	3.8	213.5
Interest expense	117.7	12.6	-	-	33.2	163.5
Interest revenue	4.1	-	-	-	0.1	4.2
Internally allocated interest (2)	-	-	-	(30.6)	30.6	-
Gain on acquisition	-	-	-	-	22.5	22.5
Income from equity investments	-	-	$4.7	-	10.6	15.3
Income tax expense (recovery)	(13.4)	18.8	-	-	(13.5)	(8.1)
Capital expenditures	533.3	41.3	-	10.8	(18.9)	566.5
Net income attributable to common shareholders	119.2	31.9	19.8	19.7	0.1	190.7
As at December 31, 2010						
Total assets	3,804.7	880.8	395.9	507.8	489.8	6,079.0
Investments subject to significant influence	-	1.1	136.7	-	108.2	246.0
Goodwill	-	113.5	53.5	-	0.4	167.4

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes that the elimination of these transactions would understate property, plant and equipment, operating, maintenance and general expenses, or regulated fuel for generation and purchased power. Eliminated transactions are included in determining reportable segments.

(2) Segment net income is reported on a basis that includes internally allocated financing costs.

5. REGULATED FUEL ADJUSTMENT

The regulated fuel adjustment related to the fuel adjustment mechanism ("FAM") for NSPI includes the effect of fuel costs in both the current and two preceding years, specifically, and as detailed in the table below:

- The difference between actual fuel costs and amounts recovered from customers in the current year. This amount, net of the incentive component, is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities".
- The recovery from (rebate to) customers of under (over) recovered fuel costs from prior years.

The regulated fuel adjustment for the years ending December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Under recovery of current year fuel costs	**$(35.1)**	$(76.6)
Recovery from (rebate to) customers of prior years' fuel costs	**26.6**	(22.4)
Fuel adjustment	**$(8.5)**	$(99.0)

The Company has recognized a deferred income tax expense related to the regulated fuel adjustment based on NSPI's enacted statutory tax rate. As at December 31, 2011, NSPI's deferred income tax liability related to the FAM was $29.0 million (2010 - $29.2 million).

The FAM regulatory asset includes amounts recognized as a fuel adjustment, associated interest that is included in "Interest expense, net", and the application of the 2010 deferral of tax benefits (see Regulatory Matters, Note 23).

The following table shows the balance sheet classification of the various components of the FAM balances as at December 31:

millions of Canadian dollars	**2011**	2010
Current regulatory asset	**$69.0**	$27.2
Long-term regulatory asset	**24.7**	65.7
FAM regulatory asset	**$93.7**	$92.9
Current deferred income tax liability	**$(21.4)**	$(8.8)
Long-term deferred income tax liability	**(7.6)**	(20.4)
FAM deferred income tax liability	**$(29.0)**	$(29.2)

6. OTHER INCOME (EXPENSES), NET

Other income (expenses), net for the years ended December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Gain on business acquisition (1) (note 18)	**$28.2**	$22.5
Gain on exchange of subscription receipts to common shares of APUC (2)	**15.1**	-
Allowance for equity funds used during construction	**13.1**	11.8
Amortization of defeasance costs	**(12.1)**	(12.1)
Foreign exchange losses	**(2.7)**	(1.1)
Foreign exchange losses recovered through the FAM	**(5.2)**	(9.4)
Recognition of regulatory asset in GBPC	**4.4**	-
Other	**2.3**	0.8
	$43.1	$12.5

(1) Emera's interest in LPH was acquired in two tranches in Q2 2010 and Q1 2011 giving rise to non-taxable gains.

(2) Pursuant to an April 2009 subscription agreement with APUC, on January 1, 2011, Emera exchanged subscription receipts it acquired in 2009 into 8.523 million APUC common shares issued at $3.25 per share, resulting in a gain of $15.1 million (after-tax gain of $12.8 million).

7. INTEREST EXPENSE, NET

Interest expense, net for the years ended December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Interest on debt (1)	**$174.8**	$154.8
Allowance for borrowed funds used during construction	**(10.9)**	(10.5)
Interest revenue	**(10.2)**	(4.2)
Other	**5.7**	8.7
	$159.4	$148.8

(1) Interest on debt includes amortization of debt financing costs, premiums and discounts.

8. INCOME TAXES

The income tax provision, for the years ended December 31, differs from that computed using the statutory rates for the following reasons:

millions of Canadian dollars		**2011**		2010
Income before provision for income taxes	**$222.7**		$191.2	
Income taxes, at statutory rates	**72.4**	**32.5%**	65.0	34.0%
Deferred income taxes on regulated income recorded as regulatory assets	**(60.3)**	**(27.1)%**	(67.9)	(35.5)%
Change in estimate of prior years expected benefit of tax deductions	**(25.2)**	**(11.3)%**	-	-
Net tax effect of equity earnings	**(8.4)**	**(3.8)%**	(5.8)	(3.0)%
Non-taxable gain on business acquisition	**(9.6)**	**(4.3)%**	(7.5)	(3.9)%
Non-deductible regulatory amortization	**5.5**	**2.5%**	11.8	6.2%
Reduction in FAM regulatory asset	**(4.7)**	**(2.1)%**	-	-
Recovery of prior year income taxes	**(1.7)**	**(0.8)%**	(4.7)	(2.5)%
Other	**(4.7)**	**(2.1)%**	1.0	0.5%
Income tax expense (recovery)	**$(36.7)**	**(16.5)%**	$(8.1)	(4.2)%

The 2011 statutory income tax rate of 32.5 percent (2010 – 34 percent) represents the combined Canadian federal and Nova Scotia provincial income tax rates which are the relevant tax jurisdictions for Emera.

The following reflects the composition of taxes on income from continuing operations for the years ended December 31:

millions of Canadian dollars	**2011**	2010
Income tax recovery – current		
Domestic	**$(45.8)**	$(45.2)
Foreign	**(2.5)**	(2.0)
Income tax expense – deferred		
Domestic	**2.5**	29.0
Foreign	**25.0**	12.3
Operating loss carry forwards	**(15.9)**	(2.2)
Income tax expense (recovery)	**$(36.7)**	$(8.1)

Foreign income before taxes was $164.1 million in 2011 and $102.5 million in 2010.

The deferred income tax assets and liabilities as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Deferred income tax assets:		
Pension and other post-retirement liabilities	**$230.4**	$173.1
Tax loss carry forwards	**74.0**	54.7
Asset retirement obligations	**42.9**	63.2
Intangibles	**27.8**	27.6
Other	**52.9**	29.5
Total deferred income tax assets before valuation allowance	**428.0**	348.1
Valuation allowance	**(17.3)**	(14.4)
Total deferred income tax assets after valuation allowance	**$410.7**	$333.7
Deferred income tax liabilities:		
Property, plant and equipment	**$469.6**	$353.9
Net investment in direct financing lease	**50.3**	32.9
Regulatory assets (deferral of FAM)	**29.0**	29.2
Other	**54.2**	49.9
Total deferred income tax liabilities	**$603.1**	$465.9
Consolidated Balance Sheet presentation		
Current deferred income tax assets	**$14.0**	$13.7
Long-term deferred income tax assets	**33.1**	31.1
Current deferred income tax liabilities	**(10.9)**	(8.5)
Long-term deferred income tax liabilities	**(228.6)**	(168.5)
Net deferred income tax liabilities	**$(192.4)**	$(132.2)

For regulated entities, to the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, a regulatory asset or liability is recognized. These amounts include a gross up to reflect the income tax associated with future revenues required to fund these deferred income tax liabilities, and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets.

In Q4 2011, NSPI modified its estimate of the expected tax benefit of tax deductions, electing to amend its tax returns for the years 2006 through 2009. This resulted in a $23.3 million reduction in income tax expense and a $3.0 million increase in interest revenue, recorded in the quarter. This change in accounting estimate has been accounted for on a prospective basis.

In Q4 2010, NSPI revised its estimate of the 2010 expected benefit from accelerated tax deductions, resulting in a $7.2 million reduction in income tax expense.

The following table summarizes as at December 31, 2011 the net operating loss ("NOL"), capital loss and tax credit carryovers and the associated carryover periods, and the valuation allowances for amounts which Emera has determined that realization is uncertain:

millions of Canadian dollars	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
NOL	$59.9	$(0.6)	$59.3	2014-2031
Capital loss	14.1	(14.1)	-	Indefinite
Investment tax credit	0.3	-	0.3	Indefinite
Total	$74.3	$(14.7)	$59.6	

As at December 31, 2011, Emera had a gross NOL carryover of $215.1 million, capital loss carryover of $64.1 million, and an investment tax credit carry forward of $0.8 million.

Considering all evidence regarding the utilization of the Company's deferred income tax assets, it has been determined that Emera is more likely than not to realize all recorded deferred income tax assets, except for the losses noted above and unrealized capital gains on certain investments. A valuation allowance has been recorded as at December 31, 2011 related to these losses and investments.

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

millions of Canadian dollars	**2011**	2010
Balance, January 1	**$12.9**	$12.1
Increases due to tax positions related to prior year	**0.3**	-
Increases due to tax positions related to current year	**2.5**	2.4
Decreases due to settlements with taxing authorities	**(1.1)**	-
Decreases due to expiration of statute of limitations	**(1.7)**	(1.6)
Balance, December 31	**$12.9**	$12.9

The total amount of unrecognized tax benefits as at December 31, 2011 was $12.9 million (2010 – $12.9 million) which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $1.3 million (2010 - $1.3 million). In the next twelve months, it is reasonable that $2.2 million of unrecognized tax benefits may be recognized due to statute expirations or settlement agreements with taxing authorities.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, US and non-US income and withholding taxes for which deferred taxes might otherwise be required have not been provided for on a cumulative amount of temporary differences related to investments in foreign subsidiaries of approximately $290.6 million as at December 31, 2011. It is impractical to estimate the amount of income and withholding tax that might be payable if a reversal of temporary differences occurred.

Emera files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. Emera's subsidiaries file Canadian, US, Barbados and St. Lucia income tax returns. As at December 31, 2011, the Company's tax years still open to examination by taxing authorities include 2002 and subsequent years. With few exceptions, the Company is no longer subject to examination for years prior to 2006.

9. EARNINGS PER SHARE

The following table reconciles the computation of basic and diluted earnings per share for the years ended December 31:

millions of Canadian dollars, except per share amounts	2011	2010
Numerator		
Net income attributable to common shareholders	**$241.1**	$190.7
Preferred stock dividends of subsidiary	**8.0**	8.0
Diluted numerator	**249.1**	198.7
Denominator		
Weighted average shares of common stock outstanding	**120.5**	113.7
Weighted average DSUs outstanding	**0.5**	0.5
Weighted average shares of common stock outstanding – basic	**121.0**	114.2
Effect of dilutive securities	**4.2**	5.1
Stock-based compensation and employee common share purchase plan	**1.0**	1.1
Weighted average shares of common stock outstanding – diluted	**126.2**	120.4
Earnings per common share		
Basic	**$1.99**	$1.67
Diluted (1)	**$1.97**	$1.65

(1) The calculation of diluted earnings per share for the years ended December 31, 2011 excluded the impact of $0.2 million (2010 – nil million) of unexercised stock options that had an anti-dilutive effect.

10. RESTRICTED CASH

Restricted cash as at December 31 consisted of the following:

millions of Canadian dollars	2011	2010
Restricted cash - BLPC (1)	**$11.2**	-
Restricted cash – Emera (2)	**-**	$58.4
Restricted cash - Other	**2.8**	0.2
	$14.0	$58.6

(1) This cash is held for the SIF at BLPC for the purpose of building an insurance fund to cover risk against damage and consequential loss to certain of BLPC's generating, transmission and distribution systems. The cash is not available for the Company to use in its operations.

(2) The cash was held for purposes of the CPUV acquisition and was not available for the Company to use in its operations.

11. RECEIVABLES, NET

Receivables, net as at December 31 consisted of the following:

millions of Canadian dollars	2011	2010
Customer accounts receivable – billed	**$310.7**	$250.8
Customer accounts receivable – unbilled	**133.6**	126.4
Total customer accounts receivable	**444.3**	377.2
Allowance for doubtful accounts	**(12.8)**	(6.6)
Customer accounts receivable, net	**431.5**	370.6
Other	**28.1**	22.3
	$459.6	$392.9

12. INVENTORY

Inventory as at December 31 consisted of the following:

millions of Canadian dollars	2011	2010
Fuel	**$134.6**	$129.1
Materials	**64.2**	48.7
	$198.8	$177.8

13. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment as at December 31 consisted of the following regulated and non-regulated assets:

millions of Canadian dollars	**2011**	2010
Generation	**$3,208.5**	$2,916.1
Transmission	**1,027.4**	919.9
Distribution	**1,893.6**	1,588.8
General plant and other	**531.4**	446.4
Total cost	**6,660.9**	5,871.2
Less: Accumulated depreciation	**(2,838.0)**	(2,462.6)
	3,822.9	3,408.6
Construction work in progress	**471.5**	334.0
Net book value	**4,294.4**	3,742.6

For the year ended December 31, 2011, AFUDC of $23.6 million (2010 – $21.7 million) was capitalized to “Property, plant and equipment”.

As a result of regulator-approved accounting policies and depreciation rates, NSPI, Bangor Hydro, and MPS defer certain costs within “Property, plant and equipment” that would not otherwise be deferred in the absence of rate-regulation. Cumulative differences between items recognized for rate regulatory purposes and applicable accounting standards including depreciation rates, AFUDC and overhead costs cannot be separately determined. Cumulative amounts related to asset retirement obligations and the associated accretion expense were $17.1 million as at December 31, 2011 (2010 – $15.3 million).

14. NET INVESTMENT IN DIRECT FINANCING LEASE

Brunswick Pipeline commenced service on July 16, 2009, transporting re-gasified LNG for Repsol Energy Canada under a 25 year firm service agreement. The agreement meets the definition of a direct financing capital lease for accounting purposes. The net investment in direct financing lease consists of the sum of the minimum lease payments and residual value net of estimated executory costs and unearned income. The unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.

millions of Canadian dollars	**2011**	2010
Total minimum lease payments to be received	**$1,440.7**	$1,495.4
Less: amounts representing estimated executory costs	**(249.8)**	(258.7)
Minimum lease payments receivable	**$1,190.9**	$1,236.7
Estimated residual value of leased property (unguaranteed)	**183.0**	183.0
Less: unearned finance lease income	**(880.1)**	(928.2)
Net investment in direct financing lease	**$493.8**	$491.5
Principal due within one year (included in “Other current assets”)	**(1.8)**	-
	$492.0	$491.5

Future minimum lease payments to be received for the next five years:

millions of Canadian dollars			For the year ended December 31		
	2012	2013	2014	2015	2016
Minimum lease payments to be received	$58.8	$58.8	$60.0	$61.6	$61.6
Less: amounts representing estimated executory costs	(9.1)	(9.2)	(9.4)	(9.6)	(9.8)
Minimum lease payments receivable	$49.7	$49.6	$50.6	$52.0	$51.8

15. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

Investments subject to significant influence consisted of the following:

	Carrying Value As at December 31		Equity Income For the Year Ended December 31		Percentage of Ownership
millions of Canadian dollars	**2011**	2010	**2011**	2010	**2011**
M&NP (1)	**$125.0**	$118.8	**$8.3**	$9.1	12.9
APUC (1) (3)	**43.7**	-	**2.4**	-	6.3
CPUV	**37.6**	-	**2.1**	-	49.999
Lucelec (1)	**26.7**	25.0	**2.0**	2.1	19.1
AHI	**5.9**	3.6	**(1.6)**	(0.4)	37.7
Maine Electric Power Company Inc.	**0.9**	0.9	**-**	-	21.7
Maine Yankee Atomic Power Company (1)	**0.3**	0.2	**-**	-	12.0
LPH (2)	**-**	111.7	**0.8**	5.2	-
GBPC (2)	**-**	-	**-**	(2.6)	-
Bear Swamp	**(17.4)**	(14.2)	**7.5**	1.9	50.0
	$222.7	$246.0	**$21.5**	$15.3	

(1) Although Emera's ownership percentage of these entities is relatively low, it does have significant influence over the operating and financial decisions of these companies through Board representation. Therefore, Emera records its investment in APUC, Maine Yankee Atomic Power Company, Lucelec and M&NP using the equity method. This is consistent with industry practice for similar investments with significant influence.

(2) Emera gained control of GBPC on December 22, 2010 and LPH on January 25, 2011; the above information does not include the income or the carrying value after gaining control, at which point the investments were consolidated.

(3) As at December 31, 2011, the market price / share is $6.42 which indicates a fair market value of this investment of $54.7, as it is a publicly traded entity.

Equity investments include a $32.9 million difference between the cost and the underlying fair value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill and is therefore not subject to amortization.

16. AVAILABLE-FOR-SALE INVESTMENTS

The available-for-sale investments consist primarily of investments in debt and equity securities held in trust on behalf of BLPC's SIF for the purpose of building an insurance fund to cover risk against damage and consequential loss to certain of BLPC's generating, transmissions and distribution systems. The SIF Fund assets are not available to the Company for use in its operations.

Emera has classified these investments as available-for-sale and recorded all such investments at their fair market value as at December 31, 2011.

Available-for-sale financial assets as at December 31 include the following:

millions of Canadian dollars	**2011**	2010
Common shares	**$1.3**	$0.8
Mutual funds	**17.8**	-
Corporate bonds, debentures, short and medium term notes	**27.7**	-
Government bonds	**7.8**	-
	$54.6	$0.8

The change in available-for-sale assets is as follows:

millions of Canadian dollars	2011	2010
Balance, beginning of the period	**$0.8**	$1.0
Resulting from acquisitions	**53.5**	-
Additions, net of foreign exchange loss	**36.5**	-
Disposals	**(35.8)**	-
	$55.0	$1.0
Change in fair value		
Gain recognized in regulatory liability	**(0.1)**	-
Loss recognized in other comprehensive income during the period	**(0.3)**	(0.2)
	$(0.4)	$(0.2)
Balance, end of the period	**$54.6**	$0.8

There were no impairment provisions for available-for-sale investments for the years ended 2011 and 2010.

The maturity profile of debt securities included in the available-for-sale assets as at December 31 is as follows:

millions of Canadian dollars	2011	2010
Maturity within 1 year	**$12.7**	-
Maturity in 1-5 years	**22.8**	-
	$35.5	-

The maximum exposure to credit risk at the reporting date is the carrying value of the debt securities. None of these financial instruments are either past due or impaired.

17. GOODWILL

The change in goodwill for the years ended December 31 is due to the following:

millions of Canadian dollars	2011	2010
Balance, January 1	**$167.4**	$87.6
Acquisitions	**26.1**	84.8
Change in foreign exchange rate	**4.2**	(5.0)
Balance, December 31	**$197.7**	$167.4

18. ACQUISITIONS

Light & Power Holdings Ltd.

On January 25, 2011, Emera acquired 7.2 million shares of LPH, the parent company of BLPC, a vertically-integrated utility and the sole provider of electricity on the island of Barbados with a franchise to produce, transmit and distribute electricity on the island until 2028, for total cash consideration of $92.6 million CAD ($92.8 million USD). As a result, Emera became the majority shareholder of LPH, with a total interest of 80.1 percent. This investment was made to increase Emera's regulated transmission, distribution and generation portfolio.

Prior to this transaction, Emera owned 38.3 percent of LPH with a carrying value of $113.5 million CAD ($113.8 million USD). The fair value of Emera's interest in LPH immediately prior to the acquisition date was $84.8 million CAD ($85.0 million USD).

The fair value of the assets of a regulated utility are generally deemed to equal book value (rate base) given the regulated utility's earnings are a function of its rate base, as determined by the regulator. The purchase price was negotiated between arms-length parties. The differential between the two amounts resulted in Emera recording a gain on acquisition of $28.2 million, which Emera has recorded as a non-taxable gain in "Other income (expenses), net" on Emera's Consolidated Statements of Income for the year ended December 31, 2011.

The valuation technique used to measure the acquisition-date fair value of the assets and liabilities of LPH was book value for regulated assets given the regulatory environment in which BLPC operates. Non-regulated assets were measured based on recent transactions. Accordingly, a third party valuation of assets and liabilities was not performed.

The purchase price allocation has been finalized. The total purchase price has been allocated to the fair value of assets and liabilities as follows:

	millions of Canadian dollars
Cash and cash equivalents	$58.4
Restricted cash	12.3
Receivables, net	23.4
Income tax receivable	0.2
Inventory	16.3
Prepaid expenses	2.9
Property, plant and equipment	292.0
Available-for-sale investments	52.5
Other non-current assets	1.6
Current portion of long-term debt	(7.5)
Account payable	(33.7)
Other current liabilities	(5.3)
Long-term debt	(43.1)
Deferred income taxes	(9.5)
Regulatory liabilities	(62.7)
ARO	(2.2)
Other long-term liabilities	(2.5)
Gain on business acquisition (1)	(28.2)
Non-controlling interest	(58.2)
Total purchase consideration	$206.7

(1) The gain shown above represents the net effect of the gain on acquisition of $56.3 million net of a loss of $28.1 million on a business combination achieved in stages, which requires the revaluation of the existing interest to the implied value from the second investment at the date of acquiring control. The gain is included in "Other income (expenses) net" in the Consolidated Statements of Income.

The Company has included operating revenues of $282.4 million and net income attributable to common shareholders of $12.0 million for BLPC in its consolidated net income attributable to common shareholders for fiscal 2011 related to the period subsequent to January 25, 2011.

The Company also incurred $2.0 million in acquisition-related costs of which $1.5 million was recorded in 2011. These costs are included in "Operating, maintenance and general expense" in the Consolidated Statements of Income.

Supplemental Pro Forma Data

The unaudited pro forma statement below gives effect to the acquisition of a controlling interest in BLPC as if the transaction had occurred at the beginning of 2010. This pro forma data is presented for informational purposes only and does not purport to be indicative of the results of future operations or of the results that would have occurred had the acquisition taken place at the beginning of 2010.

For the	Year ended December 31	
millions of Canadian dollars	**2011**	2010
Operating revenues	**$2,081.7**	$1,867.8
Net income attributable to common shareholders	**241.4**	200.9
Pro forma basic earnings per share	**$1.99**	$1.76
Pro forma diluted earnings per share	**$1.97**	$1.73

Grand Bahama Power Company Limited

On December 22, 2010, Emera acquired 50 percent of the outstanding common shares of GBPC, an integrated utility and sole provider of electricity on Grand Bahama Island; and an additional 10.7 percent interest in ICD Utilities Limited ("ICDU"), owner of the remaining 50 percent interest in GBPC, for total cash consideration of $81.6 million CAD ($82.0 million USD), giving Emera an 80.4 percent direct and indirect interest in GBPC. This investment was made to increase Emera's regulated electricity, transmission and generation portfolio.

Prior to the transaction, Emera owned 50 percent of ICDU and indirectly through this ownership 25 percent of GBPC. This interest in ICDU had a carrying value of $39.2 million CDN ($39.4 million USD). The fair value of Emera's interest in ICDU immediately prior to the acquisition date, was $36.8 million CDN ($37.0 million USD).

As a result of this transaction, the Company recorded a loss on a business acquisition achieved in stages related to the pre-existing investment of $2.4 million.

The valuation of the acquisition-date fair value of GBPC's assets and liabilities was performed by a third party. The valuation technique primarily involved the cost approach for property, plant and equipment and comparable debt issuances for long-term debt. Quoted prices or public sourced information was utilized where possible in the valuation. The purchase price allocation has been finalized. The total purchase price has been allocated to the fair value of assets and liabilities as follows:

	millions of Canadian dollars
Receivables, net	$19.2
Inventory	16.2
Prepaid expenses	1.2
Other non-current assets	0.5
Property, plant and equipment	153.4
Goodwill	75.6
Short-term debt	(1.9)
Current portion of long-term debt	(4.2)
Account payable	(20.6)
Other current liabilities	(3.5)
Long-term debt	(83.1)
Pension and post-retirement liabilities	(5.5)
Non-controlling interest	(28.9)
Total purchase consideration	$118.4

The goodwill that arose on the acquisition of GBPC is a result of expected operational efficiencies and synergies that Emera's management believes it can bring to the operation of GBPC, as well as additional strategic opportunities in the region.

The Company has included operating revenues of $124.0 million and net income attributable to common shareholders of $4.6 million for GBPC in its consolidated net income attributable to common shareholders for fiscal 2011.

The Company also incurred $4.9 million in acquisition-related costs of which $6.1 million was expensed in 2010, offset with a recovery of $1.2 million recorded in 2011. These expenses are included in "Operating, maintenance and general expense" in the "Consolidated Statements of Income."

Supplemental Pro Forma Data
The unaudited pro forma statement below gives effect to the acquisition of a controlling interest of GBPC as if the transaction had occurred at the beginning of 2010. This pro forma data is presented for informational purposes only and does not purport to be indicative of the results of future operations or of the results that would have occurred had the acquisition taken place at the beginning of 2010.

For the	Year ended December 31	
millions of Canadian dollars	**2011**	2010
Operating revenues	**$2,064.4**	$1,717.9
Net income attributable to common shareholders	**241.1**	187.3
Pro forma basic earnings per share	**$1.99**	$1.64
Pro forma diluted earnings per share	**$1.97**	$1.62

Maine & Maritimes Corporation

On December 21, 2010, Emera acquired all of the outstanding common shares of MAM, a publically held United States corporation, and the parent company of MPS for cash consideration of $77.2 million CAD ($75.8 million USD). This investment was made to increase Emera's transmission and distribution portfolio.

The valuation technique used to measure the acquisition-date fair value of the assets and liabilities of MAM was book value for regulated assets given the regulatory environment in which MPS operates. Accordingly, a third party valuation of assets and liabilities was not performed.

The purchase price allocation has been finalized. The total purchase price has been allocated to the fair value of assets and liabilities as follows:

	millions of Canadian dollars
Cash and cash equivalents	$0.6
Restricted cash	0.2
Receivables, net	8.3
Income taxes receivable	1.2
Inventory	1.1
Regulatory assets - current	9.9
Prepaid expenses	0.9
Other current assets	0.3
Property, plant and equipment	66.6
Regulatory assets – non-current	22.3
Investments subject to significant influence	0.4
Goodwill	31.7
Other non-current assets	3.9
Short-term debt	(2.3)
Current portion of long-term debt	(1.1)
Account payable	(4.8)
Regulatory liabilities - current	(0.5)
Other current liabilities	(3.3)
Long-term debt	(23.0)
Deferred income taxes	(16.3)
Derivative instruments	(3.6)
Regulatory liabilities – long-term	(5.2)
Pension and post-retirement liabilities	(7.1)
Other long-term liabilities	(3.0)
Total purchase consideration	$77.2

The goodwill that arose on the acquisition of MAM is a result of expected operational efficiencies and synergies that Emera's management believes it can bring to the operation of MAM, as well as additional strategic opportunities in the region.

The Company has included operating revenues of $34.6 million and net income attributable to common shareholders of $2.8 million for MPS in its consolidated net income attributable to common shareholders for fiscal 2011. The Company also incurred $4.7 million in acquisition-related costs which were expensed during 2010 and included in “Operating, maintenance and general expense” in the “Consolidated Statements of Income.”

Supplemental Pro Forma Data
The unaudited pro forma statement below gives effect to the acquisition of MPS as if the transaction had occurred at the beginning of 2010. This pro forma data is presented for informational purposes only and does not purport to be indicative of the results of future operations or of the results that would have occurred had the acquisition taken place at the beginning of 2010.

For the millions of Canadian dollars	Year ended December 31 **2011**	 2010
Operating revenues	**$2,064.4**	$1,642.2
Net income attributable to common shareholders	**241.1**	189.5
Pro forma basic earnings per share	**$1.99**	$1.66
Pro forma diluted earnings per share	**$1.97**	$1.64

19. SHORT-TERM DEBT

Emera’s short-term borrowings consist of commercial paper issuances, advances on the revolving credit facilities and short-term notes. Short-term debt and related the weighted-average interest rate as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	**Weighted-average interest rate**	2010	Weighted-average interest rate
Emera				
Advances on the revolving credit facilities (1)	**$2.4**	**3.50%**	$1.5	3.75%
Promissory note issued to APUC	**135.8**	**-**	27.7	-
NSPI				
Advances on the revolving credit facilities (1)	**4.6**	**3.25%**	1.6	3.50%
Commercial paper (re-classed from long-term debt) (2)	**59.3**	**1.08%**	46.7	1.07%
MPS				
Advances on the revolving credit facilities	**0.7**	**3.25%**	2.3	1.39%
GBPC				
Advances on the revolving credit facilities	**7.5**	**5.75%**	1.9	5.50%
Short-term debt	**$210.3**		$81.7	

(1) Advances on the long-term revolving credit facilities (note 20) can be made by way of overdraft on accounts for Emera and NSPI for up to $30 million and $50 million, respectively.
(2) NSPI’s commercial paper is backed by a revolving credit facility which matures in 2015. NSPI has the ability to refinance commercial paper on a long-term basis; however amounts expected to be paid through working capital are classified as short-term debt. All other drawings are classified as long-term debt (note 20).

The Company’s total short-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of Canadian dollars	**Maturity**	**2011**	2010
MPS – revolving credit facility	2012	**$10.2**	$9.9
GBPC – revolving credit facility	2012	**11.2**	10.9
Total		**21.4**	20.8
Less:			
Advances under revolving credit facilities		**8.2**	4.2
Use of available facilities		**8.2**	4.2
Available capacity under existing agreements		**$13.2**	$16.6

As at December 31, 2011, these credit facilities require commitment fees ranging from 0.20% to 0.27% basis points. The weighted average interest rate on outstanding short-term debt at December 31, 2011 was 1.78% (2010 – 1.37%).

Credit Facilities

On April 27, 2011, Maine Public Service Company renewed its existing $10 million USD revolving credit facility with Bank of America, with a new expiration date of December 31, 2012.

In October 2011, GBPC entered into a 12 month revolving credit facility for $11 million Bahamian dollars with Scotiabank (Bahamas) Limited.

20. LONG-TERM DEBT

Emera's long-term debt includes the issuances detailed below. Medium-term notes and debentures are issued under trust indentures at fixed interest rates and are unsecured unless noted below. Also included are certain bankers' acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year. Long-term debt as at December 31 consisted of the following:

millions of Canadian dollars	Stated Interest Rate	Effective Interest Rate	Maturity	**2011**	2010
Emera					
Bankers acceptances, LIBOR loans (1)	-	2.16%	4 year renewal	**$251.0**	$396.7
Medium-term notes					
Series F	4.10%	4.19%	2014	**250.0**	250.0
Series G	4.83%	4.89%	2019	**225.0**	225.0
Series H	2.96%	3.05%	2016	**250.0**	-
				725.0	475.0
Promissory note		-	2016	**1.8**	-
Capital lease obligations				**1.7**	2.5
				979.5	874.2
NSPI					
Commercial Paper (2)	-	1.08%	4 year renewal	**$312.8**	$288.4
Medium-term notes					
Series F	8.85%	8.21%	2025	**125.0**	125.0
Series I	8.40%	8.43%	2015	**70.0**	70.0
Series L	8.30%	8.96%	2036	**60.0**	60.0
Series M (3)	8.50%	7.76%	2026	**40.0**	40.0
Series N	7.60%	7.57%	2097	**50.0**	50.0
Series P	6.28%	6.28%	2029	**40.0**	40.0
Series R	7.45%	7.51%	2031	**75.0**	75.0
Series S	6.95%	7.12%	2033	**200.0**	200.0
Series T	5.75%	6.09%	2013	**300.0**	300.0
Series V	5.67%	5.71%	2035	**150.0**	150.0
Series W	5.95%	6.01%	2039	**200.0**	200.0
Series X	5.61%	5.65%	2040	**300.0**	300.0
				1,610.0	1,610.0
Debentures – Series 3	9.75%	9.99%	2019	**95.0**	95.0
Capital lease obligations				**-**	0.1
				2,017.8	1,993.5
Bangor Hydro (4)					
LIBOR loans and demand loans (5)	-	2.14%	2 year renewal	**$63.3**	$38.6
General & refunding mortgage bonds (6)					
$20 million	8.98%	8.98%	2022	**20.3**	19.9
$30 million	10.25%	10.25%	2020	**30.5**	29.8
				50.8	49.7

millions of Canadian dollars	Stated Interest Rate	Effective Interest Rate	Maturity	**2011**	2010
Bangor Hydro Continued (4)					
Senior unsecured notes					
$20 million 2002	6.09%	6.09%	2012	**20.3**	19.9
$50 million 2003 (7)	5.31%	5.31%	2018	**32.3**	36.2
$30 million 2007	5.65%	5.65%	2014	**30.5**	29.8
$20 million 2007	5.87%	5.87%	2017	**20.3**	19.9
				103.4	105.8
				217.5	194.1
MPS (4)					
Maine Public Utility Financing Bank Bonds (8)	0.46%	6.20%	2021	**$13.8**	$13.5
Maine Public Utility Financing Bank Bonds (8)	0.46%	6.32%	2025	**9.2**	8.9
LIBOR loans				**-**	1.0
Capital lease obligations				**-**	0.1
				23.0	23.5
GBPC (4)					
Unsecured notes	5.96%	5.96%	2014	**$31.9**	$35.5
Bond notes	7.07%	7.07%	2020-2023	**52.7**	49.7
				84.6	85.2
BLPC					
Royal Bank of Canada (9)	7.00%	7.00%	2021	**$11.3**	-
National Insurance Board (9)	6.65%	6.65%	2020	**10.2**	-
National Insurance Board (9)	6.875%	6.875%	2025	**10.2**	-
First Caribbean International Bank (10)	5.985%	5.985%	2015	**4.3**	-
European Investment Bank (11)	4.27%	4.27%	2013	**7.9**	-
				43.9	-
Adjustments					
Commercial Paper in NSPI re-classed to short-term debt (2)	1.08%	4 year renewal		**(59.3)**	(46.7)
Unamortized debt discount - net				**2.2**	2.1
Amount due within one year				**(35.7)**	(10.6)
				(92.8)	(55.2)
Long-Term Debt				**$3,273.5**	$3,115.3

(1) Emera's revolving credit facility matures in June 2015, at which point the Company has the intention to renew under similar terms. The credit facility can be extended annually with the approval of the syndicated banks.
(2) NSPI's commercial paper is backed by a revolving credit facility which matures in 2015. NSPI has the ability to refinance commercial paper on a long-term basis; however amounts expected to be paid through working capital are classified as short-term debt (note 19). All other drawings are classified as long-term debt.
(3) Notes extendable until 2056 at the option of the holders.
(4) Debt issued and payable in USD.
(5) Bangor Hydro's revolving credit facility matures in September 2013, at which point the Company has the intention to renew under similar terms.
(6) Secured by property, plant and equipment of Bangor Hydro.
(7) Sinking fund payments beginning in year five.
(8) The interest on these USD variable rate bonds is fixed through the MPS interest rate swaps. The 1996 Series bonds of $13.6 million, due in 2021, are fixed at 4.42 percent, while the 2000 Series bonds of $9.0 million, due in 2025, are fixed at 4.53 percent.
(9) Debt issued and payable in Barbadian dollars. Borrowings are secured under a Debenture Trust Deed which creates a first and floating charge on the Company's property, present and future.
(10) Debt issued and payable in USD. Borrowings are secured under a Debenture Trust Deed which creates a first and floating charge on the Company's property, present and future.
(11) Debt issued and payable in USD. Borrowings are guaranteed by the Government of Barbados.

The Company's total long-term credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of Canadian dollars	Maturity	2011	2010
Emera – revolving credit facility (1)	June 2015	**$700.0**	$600.0
NSPI – revolving credit facility (2)	June 2015	**500.0**	600.0
Bangor Hydro – revolving credit facility	September 2013	**81.4**	79.6
Total		**1,281.4**	1,279.6
Less:			
Borrowings under credit facilities		**634.1**	726.8
Letters of credit issued inside credit facilities		**13.7**	11.4
Use of available facilities		**647.8**	738.2
Available capacity under existing agreements		**$633.6**	$541.4

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $30 million and such advances are classified as short-term debt (note 19).
(2) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $50 million and such advances are classified as short-term debt (note 19).

Credit Facilities

In June, 2010, Emera entered into a three year revolving credit facility for $600 million with a syndicate of banks. In June, 2010, NSPI entered into a three year revolving credit facility for $600 million with a syndicate of banks. In August 2011, Emera increased its committed syndicated revolving bank line of credit from $600 million to $700 million, and NSPI reduced its committed syndicated revolving bank line of credit from $600 million to $500 million. The maturity of both facilities was extended from June 2013 to June 2015.

NSPI has an active commercial paper for up to $400 million, of which outstanding amounts are 100 percent backed by NSPI's bank line, which results in an equal amount of credit being considered drawn and unavailable.

On June 24, 2010, Bangor Hydro entered into a 39 month revolving credit facility for $80 million USD with a syndicate of banks.

Issuances

On December 13, 2011, Emera completed the issue of $250 million Series H Medium-Term Notes. The Series H Notes bear interest at a rate of 2.96 percent and yield 2.969 percent per annum until December 13, 2016.

The net proceeds of the offering will be used to repay short-term borrowings and for general corporate purposes.

Debt Covenants

Emera and certain subsidiaries debt obligations contain covenants related to the amount of debt to capitalization as defined in certain agreements. In addition, other covenants and financial reporting obligations exist. Failure to comply with these covenants could result in an event of default, which if not cured or waived, could result in the acceleration of outstanding debt obligations. As at December 31, 2011, Emera and each of its subsidiaries were in compliance with all respective financial covenants related to outstanding debt.

Debt shelf prospectus

Emera
In February 2011, Emera filed an amended and restated short form base shelf prospectus. This amendment increased the aggregate principal amount of debt securities and preferred shares that may be offered from time to time under the short form base shelf prospectus from $500 million to $650 million. As at December 31, 2011, $150 million in preferred shares and $250 million of medium term notes have been issued under the short form base shelf prospectus and shelf prospectus supplements. Concurrently

with the Canadian filing of this amendment, Emera also filed a registration statement on Form F-9 with the U.S. Securities and Exchange Commission to register debt securities and preferred shares having an aggregate initial offering price of up to $500 million for sale in the United States.

NSPI

In May 2011, NSPI filed an amendment to its amended and restated short form base shelf prospectus and an amendment to its prospectus supplement for medium-term notes (unsecured). These amendments increased the aggregate principal amount of debt securities and medium-term notes that may be offered from time to time under the short form base shelf prospectus and prospectus supplement from $500 million to $800 million. As at December 31, 2011, $300 million in medium-term notes have been issued under NSPI's short form base shelf prospectus and prospectus supplement since their initial filing in 2010.

Long-Term Debt Maturities

As at December 31, 2011, long-term debt maturities, including capital lease obligations, for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2012	2013	2014	2015	2016	Greater than 5 years	**Total**
Emera	$1.1	$0.9	$250.7	$251.6	$250.2	$225.0	$979.5
NSPI	-	300.0	-	323.5	-	1,335.0	1,958.5
Bangor Hydro	24.9	67.9	35.1	4.6	4.6	80.4	217.5
MPS	-	-	-	-	-	23.0	23.0
GBPC	4.0	4.2	15.7	8.1	-	52.6	84.6
BLPC	-	7.9	-	4.1	-	31.9	43.9
Total	$30.0	$380.9	$301.5	$591.9	$254.8	$1,747.9	$3,307.0

21. OTHER CURRENT LIABILITIES

Other current liabilities as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Accrued charges	**$69.0**	$59.6
Accrued interest on long-term debt	**38.0**	37.7
Sales taxes payable	**12.8**	7.0
Dividends payable	**2.0**	2.1
Other	**5.4**	3.9
	$127.2	$110.3

22. ASSET RETIREMENT OBLIGATIONS

Asset Retirement Obligations ("ARO") mostly relate to the reclamation of land at the thermal, hydro, and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment. Certain hydro, transmission and distribution assets may have additional ARO that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the fair value of any related ARO cannot be made at this time.

The change in ARO for the years ended December 31 is as follows:

millions of Canadian dollars	**2011**	2010
Balance, January 1	**$141.8**	$104.5
Additions	**-**	32.1
Additions due to acquisition	**2.3**	-
Liabilities settled	**(1.3)**	(1.2)
Accretion included in depreciation expense	**4.5**	3.6
Accretion deferred to regulatory asset	**1.9**	2.1
Revisions in estimated cash flows	**(49.3)**	0.7
Balance, December 31	**$99.9**	$141.8

As at December 31, 2011 and 2010, some of the Company's transmission and distribution assets may have additional conditional ARO which are not recognized in the financial statements as the fair value of these obligations could not be reasonably estimated given there is insufficient information to do so. Management will continue to monitor these obligations and a liability will be recognized in the period in which an amount becomes determinable.

During Q4, 2011, Emera Brunswick Pipeline's estimated cash flows with respect to its ARO were updated as a result of the National Energy Board's new guidelines for the calculation of reclamation and abandonment costs for Canadian pipelines. The change resulted from a change in the estimate of future reclamation and abandonment costs.

During Q2 2011, NSPI's estimated future cash flows with respect to ARO were updated to reflect the results of a settlement agreement with stakeholders which was approved by the UARB, following the completion of a depreciation study. The changes resulted from a change in estimates of retirement dates and future decommissioning costs. The new accretion rates are effective January 1, 2012.

23. REGULATORY MATTERS

NSPI

NSPI is a public utility as defined in the Public Utilities Act of Nova Scotia (the "Act") and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings held from time to time at NSPI's or the UARB's request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's target regulated return on equity ("ROE") range for 2011 was 9.1 percent to 9.6 percent based on an actual, average regulated common equity component of up to 40 percent of regulated capitalization. NSPI has a FAM, which enables NSPI to seek recovery of fuel costs through regularly scheduled rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year. The FAM has an incentive component, whereby NSPI retains or absorbs 10 percent of the over or under recovered amount to a maximum of $5 million.

In May, 2011, NSPI filed a General Rate Application ("GRA") with the UARB requesting an average 7.3 percent rate increase across all customer classes effective January 1, 2012. In November, 2011, the UARB approved a settlement agreement between NSPI and customer representatives which resulted in an average rate increase of 5.1 percent for all customers, effective January 1, 2012. Rates were approved based on a 9.2 percent ROE, applied to a 37.5 percent common equity component with a target earnings range of 9.1 percent to 9.5 percent on maximum actual equity of 40 percent.

Maine Utilities

Both Bangor Hydro and MPS' core businesses are the transmission and distribution of electricity, with distribution operations and stranded cost recoveries regulated by the Maine Public Utilities Commission ("MPUC"). Each Company's transmission operations are regulated by the Federal Energy Regulatory Commission ("FERC"). The rates for these three elements are established in distinct regulatory proceedings.

Distribution Operations

Maine Utilities' distribution businesses operate under a traditional cost-of-service regulatory structure. Distribution rates are set based on an allowed ROE of 10.2 percent, on a common equity component of 50 percent.

Transmission Operations

Bangor Hydro
Bangor Hydro's local transmission rates are set by the FERC annually on June 1, based upon a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted transmission investments and expenses. The allowed ROE for these local transmission investments is 11.14 percent. The common equity component is based upon the prior calendar year actual average balances. On June 1, 2011, Bangor Hydro's local transmission rates decreased by approximately 10 percent (2010 – increased 37 percent).

Bangor Hydro's bulk transmission assets are managed by the ISO-New England ("ISO") as part of a region-wide pool of assets. The ISO manages the regions' bulk power generation and transmission systems and administers the open access transmission tariff. Currently, Bangor Hydro, along with all other participating transmission providers, recovers the full cost of service for its transmission assets from distribution companies in New England, based on a regional formula that is updated on June 1 of each year. This formula is based on prior year regionally funded transmission investments and expenses, adjusted for current year forecasted investments and expenses. Bangor Hydro's allowed ROE for these transmission investments ranges from 11.64 percent to 12.64 percent, and the common equity component is based upon the prior calendar year average balances. The cost recovery is recorded as transmission pool revenue in the Consolidated Statements of Income. The participating transmission providers are also required to contribute to the cost of service of such transmission assets on a ratable basis according to the proportion of the total New England load that their customers represent. These transmission pool expenses are recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income.

On June 1, 2010, Bangor Hydro's regional transmission revenue requirement increased by 22 percent, and on June 1, 2011, it increased by a further 9 percent.

MPS
MPS local transmission rates are set annually based on a formula through its Open Access Transmission Tariff ("OATT"). Rates derived from the previous calendar year results go into effect June 1 for wholesale customers and July 1 for retail customers. The allowed ROE for transmission operations is 10.5 percent, and is based on the actual prior calendar year common equity balances. The allowed ROE is determined by negotiation with customers in the formula change years of the OATT, which occur every three years. The last OATT formula change year was 2009. On June 1, 2011, MPS' local transmission rates increased by 3 percent for wholesale customers (2010 – increased 63 percent) and by 4 percent for retail customers (2010 – increased by 64 percent) on July 1, 2011.

MPS' electric service territory is not interconnected to the New England bulk power system, and MPS is not a member of the ISO.

Stranded Cost Recoveries
Electric utilities in Maine are entitled to recover all prudently incurred stranded costs resulting from the restructuring of the industry in 2000 that could not be mitigated or that arose as a result of rate and accounting orders issued by the MPUC. Unlike T&D operational assets, which are generally sustained with new investment, the net stranded cost regulatory asset pool diminishes over time as elements are amortized through charges to income and recovered through rates. Generally, regulatory rates to recover stranded costs are set every three years, on a levelized basis, and determined under a traditional cost-of-service approach.

Bangor Hydro
Bangor Hydro's net regulatory assets primarily include the costs associated with the restructuring of an above-market power purchase contract and the unamortized portion on its loss on the sale of its investment in the Seabrook nuclear facility. These net regulatory assets total approximately $65.3 million as at December 31, 2011 (2010 – $74.9 million) or 8 percent of Bangor Hydro's net asset base (2010 – 10 percent).

In May 2011, the MPUC approved an approximate 27 percent increase in Bangor Hydro's stranded cost rates for the period of June 1, 2011 to February 28, 2014. The increased stranded cost revenues are offset, for the most part, by changes in regulatory amortizations, purchased power expense and resale of purchased power. The allowed ROE used in setting these new stranded cost rates is 7.4 percent, with a common equity component of 48 percent.

While the stranded cost revenue requirements differ throughout the period due to changes in annual stranded costs, the actual annual stranded cost revenues are the same during the period. To levelize the impact of the varying revenue requirements, cost or revenue deferrals are recorded as a regulatory asset or liability, and addressed in subsequent stranded cost rate proceedings, where customer rates are adjusted accordingly.

MPS
In December 2011, the MPUC approved MPS' stranded cost rates for the three-year period January 1, 2012 through December 31, 2014. This revised three-year agreement, which amortizes essentially all of MPS' remaining stranded costs, has an ROE of 7.2 percent and a common equity component of 50 percent. Any residual stranded costs remaining after December 31, 2014 will be recovered in future rate proceedings.

The Barbados Light & Power Company Limited

BLPC is a vertically integrated utility and sole provider of electricity on the island of Barbados.

BLPC is subject to regulation under the Utilities Regulation (Procedural) Rules 2003 ("Rules") by Fair Trading Commission, Barbados, an independent regulator. The Rules give the Fair Trading Commission, Barbados utility regulation functions which include establishing principles for arriving at rates to be charged, monitoring the rates charged to ensure compliance, and setting the maximum rates for regulated utility services. The government of Barbados has granted BLPC a franchise to produce, transmit and distribute electricity on the island until 2028.

BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and providing an appropriate return to investors. BLPC's approved regulated return on assets for 2011 is 10 percent.

BLPC's first rate adjustment since 1983 was approved in January 2010 and was effective March 1, 2010.

All BLPC fuel costs are passed to customers through the fuel surcharge. Fair Trading Commission, Barbados has approved the calculation of the fuel surcharge, which is adjusted on a monthly basis. BLPC has the ability to carryover an under-recovery to later months to smooth the fuel surcharge for customers.

Grand Bahama Power Company Limited

GBPC is a vertically-integrated utility and sole provider of electricity on Grand Bahama Island. The Grand Bahama Port Authority ("GBPA") regulates the utility and has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit, and distribute electricity on the island until 2054. There is a fuel pass through mechanism and flexible tariff adjustment policy to ensure that costs are recovered and a reasonable return earned.

The base tariff for GBPC includes a component to recover the cost of $20 USD per barrel of oil consumed by GBPC for generation of electricity. The amount by which actual fuel costs exceed $20 USD dollars per barrel is recovered or rebated through the fuel surcharge, which is adjusted on a monthly basis. The methodology for calculating the amount of the fuel surcharge has been approved by GBPA.

Brunswick Pipeline

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Canaport™ re-gasified liquefied natural gas ("LNG") import terminal near Saint John, New Brunswick, to markets in the northeastern United States. Brunswick Pipeline entered into a 25 year firm service agreement commencing in July 2009 with Repsol Energy Canada. The pipeline is considered a Group II pipeline regulated by the National Energy Board ("NEB"). The NEB Gas Transportation Tariff is filed by Brunswick Pipeline in compliance with the requirements of the NEB Act and sets forth the terms and conditions of the transportation rendered by Brunswick Pipeline.

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because it is probable that they will be recovered through future rates or tolls collected from customers. Management believes that existing regulatory assets are probable of recovery either because the Company received specific approval from the appropriate regulator, or due to regulatory precedent set for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

Regulatory assets and liabilities as at December 31 consisted of the following:

millions of Canadian dollars	2011	2010
Regulatory assets		
Deferred income tax regulatory asset	**$94.8**	$64.8
Regulated fuel adjustment mechanism	**93.7**	92.9
Unamortized defeasance costs	**82.4**	94.6
Deferrals related to derivative instruments	**48.4**	40.4
Pre-2003 income tax and related interest	**42.0**	56.9
Purchase power contracts	**14.2**	24.3
Seabrook nuclear project	**11.8**	14.3
Pension and postretirement medical plan	**9.7**	11.6
Deferral of income and capital taxes not included in Q1 2005 rates	**7.8**	10.0
Smart Grid	**7.4**	4.8
Stranded cost revenue & purchase power reconciliation deferrals	**5.7**	5.3
Deferral of demand side management	**5.4**	7.5
Hydro-Quebec Obligation	**5.4**	5.7
Asset impairment recovery	**4.7**	-
Deferred leasing costs	**4.4**	-
Other	**16.0**	12.3
	$453.8	$445.4
Current	**$141.6**	$90.5
Long-term	**312.2**	354.9
Total regulatory assets	**$453.8**	$445.4
Regulatory liabilities		
Self-Insurance Fund	**$64.7**	-
Deferrals related to derivative instruments	**45.6**	$64.1
Deferred income tax regulatory liabilities	**19.5**	36.6
2010 renewable tax benefits deferral	**-**	14.5
Other	**1.2**	5.0
	$131.0	$120.2
Current	**$23.9**	$55.0
Long-term	**107.1**	65.2
Total regulatory liabilities	**$131.0**	$120.2

Deferred Income Tax Regulatory Asset and Liability

To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, a regulatory asset or liability is recognized.

Regulated Fuel Adjustment Mechanism

As discussed in Note 5, the UARB approved the implementation of a FAM for NSPI effective January 1, 2009. The change in the FAM balance for the years ended December 31 consisted of the following:

millions of Canadian dollars	2011	2010
Balance, January 1	**$92.9**	$(9.9)
Under recovery of current year fuel costs	**35.1**	76.6
(Recovery from) rebate to customers of prior years' fuel costs	**(26.6)**	22.4
Application of the deferral related to tax benefits from 2010	**(14.5)**	-
Interest revenue on FAM balance	**6.8**	3.8
Balance, December 31	**$93.7**	$92.9

Unamortized Defeasance Costs

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities held in trust, which as at December 31, 2011, totaled $1.0 billion (2010 – $1.0 billion). The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB.

Deferrals Related to Derivative Instruments

NSPI defers changes in fair value of derivatives that are documented as economic hedges, and for which the NPNS exception has not been taken as a regulatory asset or liability as approved by the UARB. The gain or loss is recognized when the derivatives settle in fuel for generation and purchased power, other expenses, inventory or property, plant and equipment, depending on the nature of the item being economically hedged.

Pre-2003 Income Tax and Related Interest

NSPI has a regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers as a result of capital cost allowance deductions NSPI claimed in its corporate income tax return that were disallowed in a Supreme Court decision. NSPI applied to the UARB to include recovery of these costs in customer rates. In February 2007, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

In January 2010, NSPI reached an agreement with stakeholders on its calculation of the Company's regulated ROE. The agreement provides NSPI with flexibility in amortizing its pre-2003 income tax regulatory asset such that NSPI has flexibility in recognizing additional amortization in current periods and reducing amortization in future periods. The approval of the 2012 General Rate Decision provided continuation of this flexibility. For the year ended December 31, 2011, NSPI recorded an additional discretionary $0.1 million (2010 - $4.8 milliom) of regulatory amortization expense.

Power Purchase Contracts

Bangor Hydro has power purchase contracts, which it was required to negotiate when oil prices were high, with several independent power producers. Bangor Hydro attempted to alleviate the adverse impact of these high-cost contracts and in doing so incurred costs to restructure certain of the contracts. The MPUC has allowed Bangor Hydro to defer these costs and recover them in stranded cost rates. The contract restructuring costs are being recovered over a 20-year period ended in June 2018. In 2011, Bangor Hydro entered into a 20-year power purchase contract with a wind farm to purchase 20 percent of the energy generated. As with the Company's other power purchase contracts, the MPUC has allowed Bangor Hydro full cost recovery for this contract.

Seabrook Nuclear Project

Bangor Hydro and MPS were participants in the Seabrook nuclear project in Seabrook, New Hampshire. In 1986 Bangor and MPS sold their respective interests with a combined cost of approximately $179.1 million. Both companies reached separate agreements with the MPUC providing for the recovery through customer rates of, in Bangor Hydro's case 70 percent of 1984 year-end investment in Seabrook Unit 1 over 30 years ending in October 2015 and in MPS's case, 60 percent costs associated with Seabrook Units 1 and 2 over 30 years ending in 2016.

Pension and Postretirement Medical Plan

As a result of purchase accounting, all unrecognized actuarial gains and losses, prior service cost, and the net transition asset/liability associated with the pension and postretirement medical benefit plans were eliminated as a result of the BHE and MPS mergers with Emera. As a result of regulatory accounting, a regulatory asset of $30 million, equal to these unrecognized amounts was established at the merger dates. BHE and MPS are amortizing the regulatory asset balance over the same period at which the corresponding gains and losses were being amortized when they were a component of pension and postretirement benefit expense.

Deferral of Income and Capital Taxes Not Included in Q1 2005 Rates

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. As a result, NSPI deferred $16.7 million, consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes. The UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

Smart Grid

In 2010, BHE received an Accounting Order from the MPUC which allowed for the deferral of costs associated with the BHE's Smart Grid project for future recovery.

Stranded Cost Revenue & Purchased Power Reconciliation deferral

Bangor Hydro and MPS have full recovery of stranded cost revenues and expenses, with deferral of variances between actual amounts and those used to set rates. Stranded cost rates are adjusted periodically to account for these cost deferrals.

Deferral of Demand Side Management

The UARB agreed to allow NSPI to defer up to $12.8 million of demand side management expenditures for the period January 1, 2008 through December 31, 2009, to be recovered in rates over six years commencing January 1, 2009.

Hydro-Quebec Obligation

The obligation associated with Hydro-Quebec represents the estimated present value of Bangor Hydro's estimated future payments for net costs associated with ownership and operation of the Hydro-Quebec intertie between the New England utilities and Hydro-Quebec. The obligation has been recognized in other liabilities and the MPUC has permitted recovery of this obligation. The regulatory asset and obligation are being reduced as expenses are incurred with the reduction of the regulatory asset amortized to purchase power expense.

Asset Impairment Recovery

On July 14, 2011, GBPA approved the recovery of a $4.7 million asset impairment charge recorded in 2010. As a result, the charge was reversed through earnings in Q3, 2011, and instead recorded as a regulatory asset which will be amortized into income over a 25 year period commencing upon completion of the new 52 MW diesel generation unit scheduled to be on line mid-2012.

Deferred Leasing Costs

On April 12, 2011, GBPA approved as part of the fuel surcharge the recovery of the net costs of leasing the temporary generation required to meet peak demand for electricity until the commission of a new 52

MW power plant. The amount by which the actual cost of the temporary generation exceeds what has been recovered through the fuel surcharge has been recorded as a regulatory asset which will be amortized into income.

Self-Insurance Fund

LPH has established a self-insurance fund ("SIF") primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. LPH holds a variable interest in the SIF for which it was determined that LPH was the primary beneficiary and, accordingly, the SIF must be consolidated by LPH. In its determination that LPH controls the SIF, management considered that in substance the activities of the SIF are being conducted on behalf of LPH's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because LPH, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF. The SIF Fund assets are not available to the Company for use in its operations.

2010 Renewable Tax Benefits Deferral

In 2010, the UARB granted NSPI approval to defer certain tax benefits related to renewable energy projects arising in 2010. In 2011, the UARB approved an agreement NSPI reached with stakeholders to apply the deferral against the FAM regulatory asset, which reduced the FAM regulatory asset effective January 1, 2011. The application of the deferral reduced the amount of the FAM balance outstanding with the reduction applied to the amount that would otherwise be recovered from customers in 2012.

24. DERIVATIVE INSTRUMENTS

The Company enters into futures, forwards, swaps and option contracts as part of its risk management strategy to limit exposure to:

- commodity price fluctuations related to the purchase and sale of commodities in the course of normal operations;
- foreign exchange fluctuations on foreign currency denominated purchases and sales; and
- interest rate fluctuations on debt securities.

The Company also enters into physical contracts for energy commodities. Collectively, these contracts are considered "derivatives". The Company accounts for derivatives under one of the following four approaches:

1. Physical contracts that meet the NPNS exception are not recognized on the balance sheet; they are recognized in income when they settle. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exception if the criteria are no longer met.

2. Derivatives that qualify for hedge accounting are recorded at fair value on the balance sheet. Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge the identified cash flow risk both at the inception and over the term of the derivative. Specifically for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to AOCL and recognized in income in the same period the related hedged item is realized. Any ineffective portion of the change in fair value from cash flow hedges is recognized in net income in the reporting period.

   Where the documentation or effectiveness requirements are not met, the derivatives are recognized at fair value with any changes in fair value recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

3. Derivatives entered into by NSPI, that are documented as economic hedges, and for which the NPNS exception has not been taken, receive regulatory deferral as approved by the UARB. These derivatives are recorded at fair value on the balance sheet as derivative assets or

liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized when the derivatives settle. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates through the FAM.

4. Derivatives that do not meet any of the above criteria are designated as HFT and are recognized on the balance sheet at fair value. All gains and losses are recognized in net income of the period unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category when another accounting treatment applies.

Derivative assets and liabilities relating to the foregoing categories as at December 31 consisted of the following:

	Derivative Assets		Derivative Liabilities	
millions of Canadian dollars	**2011**	2010	**2011**	2010
Current				
Cash flow hedges				
Power and gas swaps	**-**	-	**$8.1**	$6.4
Foreign exchange forwards	**$2.7**	$2.4	**0.5**	-
	2.7	2.4	**8.6**	6.4
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**5.4**	23.6	**0.1**	1.9
Natural gas purchases and sales	**0.7**	0.8	**33.5**	20.3
Heavy fuel oil (“HFO”) purchases	**-**	1.9	**-**	1.3
Foreign exchange forwards	**6.0**	2.1	**-**	1.2
Physical natural gas purchases and sales	**4.2**	4.3	**0.1**	-
	16.3	32.7	**33.7**	24.7
HFT derivatives				
Power swaps and physical contracts	**1.4**	10.5	**1.2**	2.6
Foreign exchange forwards	**-**	1.4	**-**	-
Natural gas swaps, futures, forwards and physical contracts	**10.9**	7.6	**10.6**	8.0
	12.3	19.5	**11.8**	10.6
Total gross current derivatives	**31.3**	54.6	**54.1**	41.7
Impact of master netting agreements with intent to settle net or simultaneously	**(4.0)**	(4.9)	**(4.0)**	(4.9)
Total current derivatives	**27.3**	49.7	**50.1**	36.8
Long-term				
Cash flow hedges				
Power swaps	**0.2**	0.5	**12.8**	8.3
Interest rate swaps	**-**	-	**6.2**	3.6
Foreign exchange forwards	**2.8**	4.1	**0.2**	-
	3.0	4.6	**19.2**	11.9
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**6.7**	18.5	**-**	-
Natural gas purchases and sales	**-**	0.1	**5.1**	1.8
Foreign exchange forwards	**18.2**	2.2	**7.9**	9.4
Physical natural gas purchases and sales	**3.7**	8.1	**-**	-
	28.6	28.9	**13.0**	11.2
HFT derivatives				
Power swaps and physical contracts	**0.9**	1.0	**0.8**	0.9
Natural gas swaps, futures, forwards and physical contracts	**6.8**	2.0	**5.4**	5.4
	7.7	3.0	**6.2**	6.3
Total gross long-term derivatives	**39.3**	36.5	**38.4**	29.4
Impact of master netting agreements with intent to settle net or simultaneously	**0.3**	(0.5)	**0.3**	(0.5)
Total long-term derivatives	**39.6**	36.0	**38.7**	28.9
Total derivatives	**$66.9**	$85.7	**$88.8**	$65.7

Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Cash Flow Hedges

The Company enters into various derivatives designated as cash flow hedges. Emera enters into power swaps to limit Bear Swamp's exposure to purchased power prices. The Company also enters into foreign exchange forwards to hedge the currency risk for revenue streams and capital projects denominated in foreign currency for Brunswick Pipeline and Bayside Power, respectively. MPS entered into an interest rate swap to hedge the fluctuation in interest rates on long-term debt.

As previously noted, the effective portion of the change in fair value of these derivatives is included in AOCL, until the hedged transactions are recognized in income. The ineffective portion is recognized in income of the period. The table below shows the amounts related to cash flow hedges recorded in AOCL and income for the years ended December 31, 2011:

millions of Canadian dollars			**2011**		2010
	Power and Gas Swaps	**Interest Rate Swaps**	**Foreign Exchange Forwards**	Power Swaps	Foreign Exchange Forwards
Unrealized loss in non-regulated fuel and purchased power – ineffective portion	**$(0.4)**	**-**	**-**	-	-
Realized loss in non-regulated fuel and purchased power	**(7.0)**	**-**	**-**	$(8.6)	-
Realized gain in regulated operating revenue	**-**	**-**	**$2.7**	-	-
Realized loss in other income (expenses), net	**-**	**-**	**(0.3)**	-	-
Total (losses) gains in income	**$(7.4)**	**-**	**$2.4**	$(8.6)	-
Total unrealized (loss) gain in OCL – effective portion, net of tax	**$(5.9)**	**$(1.4)**	**$(1.4)**	$(0.3)	$6.4

The Company expects $5.0 million (after-tax) of unrealized losses currently in AOCL to be reclassified into net income within the next twelve months, as the underlying hedged transactions settle.

As at December 31, 2011, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	2012	2013	2014	2015	2016
Power swaps (megawatt hours ("MWh")) purchases	0.3	0.3	0.3	0.3	0.3
Gas swaps (Mmbtu) purchases	1.6	-	-	-	-
Foreign exchange forwards (EURO) purchases	9.6	-	-	2.8	-
Foreign exchange forwards (USD) sales	$53.8	$48.0	$15.0	$9.0	$6.0

In addition, the Company has interest rate swaps on long-term debt of $13.8 million until 2021 and $9.2 million until 2025.

Regulatory Deferral

As previously noted, NSPI receives approval from the UARB for regulatory deferral of gains and losses on certain derivatives documented as economic hedges that do not qualify for hedge accounting, including certain physical contracts that do not qualify for the NPNS exemption.

For the years ended December 31, the Company has recorded the following realized and unrealized gains (losses) with respect to derivatives receiving regulatory deferral:

	Regulatory Assets		Regulatory Liabilities	
millions of Canadian dollars	**2011**	2010	**2011**	2010
Current				
Commodity swaps and forwards				
Coal purchases	**$(1.0)**	$(20.2)	**$17.3**	$(15.9)
Natural gas purchases and sales	**13.7**	3.5	**(0.4)**	0.1
HFO purchases	**(1.3)**	(1.2)	**1.9**	8.0
Foreign exchange forwards	**(1.6)**	(20.0)	**(3.9)**	9.0
Physical natural gas purchases and sales	**0.1**	(3.9)	**0.1**	(3.9)
Long-term				
Commodity swaps and forwards				
Coal purchases	**-**	(15.3)	**11.8**	(9.0)
Natural gas purchases and sales	**3.3**	(0.2)	**0.1**	(0.1)
HFO purchases	**-**	(1.3)	**-**	2.0
Foreign exchange forwards	**(1.5)**	6.7	**(16.0)**	18.1
Physical natural gas purchases and sales	**-**	-	**4.4**	(3.9)

Regulatory Impact Recognized in Net Income

For the years ended December 31, the Company recognized the following (losses) gains related to derivatives receiving regulatory deferral as follows:

millions of Canadian dollars	**2011**	2010
Other expenses, net	**-**	$1.5
Regulated fuel for generation and purchased power	**$(21.3)**	(66.8)
Net losses	**$(21.3)**	$(65.3)

Commodity Swaps and Forwards

As at December 31, 2011, the Company had the following notional volumes of outstanding commodity swaps and forward contracts designated for regulatory approval that are expected to settle as outlined below:

	2012	2013	2014
millions	Purchases	Purchases	Purchases
Coal (metric tonnes)	**0.5**	0.3	0.1
Natural gas (Mmbtu)	**20.1**	7.6	-

Foreign Exchange Swaps and Forwards

As at December 31, 2011, the Company had the following notional volumes of foreign exchange swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

	2012	2013	2014	2015	2016
Fuel purchases exposure (millions of US dollars)	**$256.0**	$212.0	$210.0	$210.0	$120.0
Weighted average rate	**0.9912**	1.0251	1.0106	1.0090	0.9814
% of USD requirements	**81.3%**	67.3%	66.7%	66.7%	38.1%

Held-for-Trading Derivatives

In the ordinary course of its business, Emera enters into physical contracts for the purchase and sale of natural gas; and power and natural gas swaps, forwards, and futures to economically hedge those physical contracts. These derivatives are all considered HFT.

For the years ended December 31, the Company has recognized the following realized and unrealized gains (losses) with respect to HFT derivatives:

millions of Canadian dollars	**2011**	2010
Power swaps and physical contracts in non-regulated operating revenues	**$(5.9)**	$9.4
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**19.9**	11.8
Foreign exchange forwards in other income (expenses), net	**(0.1)**	2.7
	$13.9	$23.9

As at December 31, 2011, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2012	2013	2014	2015	2016	2017
Natural gas purchases (Mmbtu)	89.0	44.3	29.8	22.4	5.8	-
Natural gas sales (Mmbtu)	47.1	14.6	3.7	1.8	-	-
Power purchases (MWh)	0.2	-	-	-	-	-
Power sales (MWh)	0.2	-	-	-	-	-
Foreign exchange forwards (USD)	-	-	-	-	-	-

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers, energy marketing collateral deposits and derivative assets. Credit risk is the potential loss from counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties and deposits or collateral are requested on any high risk accounts.

The Company assesses the potential for credit losses on a regular basis, and where appropriate, maintains provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

As at December 31, 2011, the maximum exposure the Company has to credit risk is $414.9 million (2010 - $412.3 million) which includes accounts receivable net of collateral/deposits and assets related to derivatives.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, foreign exchange and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The total cash deposits/collateral on hand as at December 31, 2011 was $111.6 million (2010 - $66.3 million) which mitigates the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements (“ISDA”), North American Energy Standards Board agreements (“NAESB”) and, or Edison Electric Institute agreements. The Company believes that entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at December 31, 2011, the Company had $92.3 million (2010 - $55.9 million) in financial assets, considered to be past due, which have been outstanding for an average 68 days. The fair value of these financial assets is $80.0 million (2010 - $49.2 million), the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric revenue.

Concentration risk

The Company’s concentrations of risk as at December 31 consisted of the following:

	2011 millions of Canadian dollars	**% of total exposure**	2010 millions of Canadian dollars	% of total exposure
Receivables, net				
Regulated utilities				
Residential	**141.5**	**27%**	115.8	24%
Commercial	**92.8**	**18%**	64.0	13%
Industrial	**34.5**	**7%**	38.0	8%
Other	**28.0**	**5%**	27.4	6%
	296.8	**57%**	245.2	51%
Trading group				
Credit rating of A- or above	**7.0**	**1%**	10.6	2%
Credit rating of BBB- to BBB+	**5.5**	**1%**	7.1	1%
Not rated – fully collateralized	**11.7**	**2%**	6.2	1%
Not rated	**27.8**	**5%**	39.7	9%
	52.0	**9%**	63.6	13%
Other accounts receivable	**110.8**	**21%**	84.1	18%
	459.6	**87%**	392.9	82%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**44.3**	**9%**	56.6	12%
Credit rating of BBB- to BBB+	**10.2**	**2%**	11.8	2%
Not rated	**12.4**	**2%**	17.3	4%
	66.9	**13%**	85.7	18%
	$526.5	**100%**	$478.6	100%

Cash Collateral

The Company’s cash collateral positions as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Cash collateral provided to others	**$71.6**	$41.6
Cash collateral received from others	**5.7**	3.0

Collateral is posted in the normal course of business based on the Company’s creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company’s derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt to fall below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at December 31, 2011, the total fair value of these derivatives, was a net liability position is $88.8 million (2010 – $65.7 million). If the credit ratings of the Company were reduced below investment grade the full value of the net liability position could be required to be posted as collateral for these derivatives.

25. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exception (see note 24), and uses a market approach to do so. The three levels of the fair value hierarchy are defined as follows:

Level 1 Valuations - Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 Valuations - Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 Valuations - Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally-developed inputs. Emera's primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The following tables set out the classification of the methodology used by the Company to fair value its derivatives as at December 31:

				2011
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash flow hedges				
Power and gas swaps	**$0.2**	**-**	**-**	**$0.2**
Foreign exchange forwards	**-**	**$5.5**	**-**	**5.5**
	0.2	**5.5**	**-**	**5.7**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**12.1**	**-**	**12.1**
Natural gas purchases and sales	**(0.4)**	**0.7**	**-**	**0.3**
Foreign exchange forwards	**-**	**24.2**	**-**	**24.2**
Physical natural gas purchases and sales	**-**	**-**	**$7.9**	**7.9**
	(0.4)	**37.0**	**7.9**	**44.5**
HFT derivatives				
Power swaps and physical contracts	**0.3**	**-**	**1.6**	**1.9**
Natural gas swaps, futures, forwards and physical contracts	**-**	**10.4**	**4.4**	**14.8**
	0.3	**10.4**	**6.0**	**16.7**
Total assets	**0.1**	**52.9**	**13.9**	**66.9**

millions of Canadian dollars	Level 1	Level 2	Level 3	2011 Total
Liabilities				
Cash flow hedges				
Power and gas swaps	**$20.9**	**-**	**-**	**$20.9**
Foreign exchange forwards		**$0.7**	**-**	**0.7**
Interest rate swaps	**-**	**6.2**	**-**	**6.2**
	20.9	**6.9**	**-**	**27.8**
Regulatory deferral				
Commodity swaps and forwards				
Natural gas purchases and sales	**38.3**	**-**	**-**	**38.3**
Foreign exchange forwards	**-**	**7.9**	**-**	**7.9**
Physical natural gas purchases and sales	**-**	**-**	**$0.1**	**0.1**
	38.3	**7.9**	**0.1**	**46.3**
HFT derivatives				
Power swaps and physical contracts	**0.3**	**-**	**1.3**	**1.6**
Natural gas swaps, futures, forwards and physical contracts	**2.7**	**7.3**	**3.1**	**13.1**
	3.0	**7.3**	**4.4**	**14.7**
Total liabilities	**62.2**	**22.1**	**4.5**	**88.8**
Net (liabilities) assets	**$(62.1)**	**$30.8**	**$9.4**	**$(21.9)**

millions of Canadian dollars	Level 1	Level 2	Level 3	2010 Total
Assets				
Cash flow hedges				
Power and gas swaps	$0.5	-	-	$0.5
Foreign exchange forwards	-	$6.5	-	6.5
	0.5	6.5	-	7.0
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases (1)	-	41.2	-	41.2
Natural gas purchases and sales (2)	0.1	-	-	0.1
HFO purchases	-	1.9	-	1.9
Foreign exchange forwards	-	4.3	-	4.3
Physical natural gas purchases and sales	-	-	$12.4	12.4
	0.1	47.4	12.4	59.9
HFT derivatives				
Power swaps and physical contracts	-	-	9.0	9.0
Foreign exchange forwards	-	1.4	-	1.4
Natural gas swaps, futures, forwards and physical contracts	0.5	1.4	6.5	8.4
	0.5	2.8	15.5	18.8
Total assets	1.1	56.7	27.9	85.7
Liabilities				
Cash flow hedges				
Power and gas swaps	$14.7	-	-	$14.7
Interest rate swaps	-	$3.6	-	3.6
	14.7	3.6	-	18.3
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases (1)	-	1.0	-	1.0
Natural gas purchases and sales (2)	21.3	-	-	21.3
HFO purchases	-	1.3	-	1.3
Foreign exchange forwards	-	10.6	-	10.6
	21.3	12.9	-	34.2
HFT derivatives				
Power swaps and physical contracts	-	-	$1.3	1.3
Natural gas swaps, futures, forwards and physical contracts	6.0	1.5	4.4	11.9
	6.0	1.5	5.7	13.2
Total liabilities	42.0	18.0	5.7	65.7
Net (liabilities) assets	$(40.9)	$38.7	$22.2	$20.0

(1) Balance was reclassified to Level 2 from Level 1
(2) Balance was reclassified to Level 1 from Level 3

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2011 was as follows:

	Regulatory Deferral	*Trading Derivatives*		
millions of Canadian dollars	Physical natural gas purchases and sales	Power	Natural Gas	Total
Balance, January 1	$12.4	$9.0	$6.5	$27.9
Reduction of benefit included in regulated fuel for generation and purchased power	(4.2)	-	-	(4.2)
Unrealized losses included in regulatory assets or liabilities	(0.3)	-	-	(0.3)
Total realized and unrealized (losses) gains included in non-regulated operating revenues	-	(7.4)	(2.1)	(9.5)
Balance, December 31	$7.9	$1.6	$4.4	$13.9

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2010 was as follows:

	Regulatory Deferral	*Trading Derivatives*		
millions of Canadian dollars	Physical natural gas purchases and sales	Power	Natural Gas	Total
Balance, January 1	-	$1.3	$4.4	$5.7
Unrealized losses included in regulatory assets or liabilities	$0.1	-	-	0.1
Total realized and unrealized (losses) gains included in non-regulated operating revenues	-	-	(1.3)	(1.3)
Balance, December 31	$0.1	$1.3	$3.1	$4.5

The financial assets and liabilities included on the balance sheet that are not measured at fair value as at December 31 consisted of the following:

		2011		2010
millions of Canadian dollars	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-term debt (including current portion)	**$3,309.2**	**$3,935.0**	$3,125.9	$3,520.8

The fair values of long-term debt instruments are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturity, without considering the effect of third party credit enhancements.

All other financial assets and liabilities such as cash and cash equivalents, restricted cash, accounts receivable, short-term debt and accounts payable are carried at cost. The carrying value approximates fair value due to the short-term nature of these financial instruments.

26. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees; and plans providing non-pension benefits for its retirees in Nova Scotia, Maine, Barbados and Grand Bahama Island.

Emera acquired control of LPH, the parent company of BLPC, in January 2011; therefore, it is not included in the December 31, 2010 comparative information.

Benefit Obligation and Plan Assets

The changes in Benefit Obligation and Plan Assets, and the Funded Status for all plans for the years ended December 31 were as follows:

	2011		2010	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Change in Projected Benefit Obligation and Accumulated Post-retirement Benefit Obligation				
Balance, January 1	**$1,048.3**	**$88.2**	$898.1	$83.4
Service cost	**15.4**	**2.9**	11.3	2.4
Plan participant contributions	**6.2**	**0.2**	5.7	0.2
Interest cost	**56.6**	**4.7**	56.6	4.7
Plan amendments	**-**	**(0.1)**	(1.0)	-
Benefits paid	**(49.5)**	**(5.5)**	(44.5)	(6.2)
Actuarial losses	**85.6**	**8.0**	128.0	6.2
Foreign currency translation adjustment	**2.8**	**1.2**	(5.9)	(2.5)
Balance, December 31	**1,165.4**	**99.6**	1,048.3	88.2
Change in Plan assets				
Balance, January 1	**724.2**	**$3.4**	$663.3	$3.3
Employer contributions	**51.9**	**5.3**	39.9	5.8
Plan participant contributions	**6.2**	**0.2**	5.7	0.2
Benefits paid	**(49.5)**	**(5.5)**	(44.5)	(6.2)
Actual return on assets, net of expenses	**(11.9)**	**-**	63.6	0.3
Foreign currency translation adjustment	**1.5**	**-**	(3.8)	-
Balance, December 31	**722.4**	**3.4**	724.2	3.4
Funded Status, end of year	**$(443.0)**	**$(96.2)**	$(324.1)	$(84.8)

As at December 31, the aggregate financial position for all pension plans where the Projected Benefit Obligation (PBO) or, for post-retirement benefit plans, the Accumulated Post-retirement Benefit Obligation (APBO), exceeds the plan assets was as follows:

Plans with PBO/APBO in excess of Plan assets	**2011**		2010	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
PBO/APBO	**$1,163.2**	**$99.6**	$1,046.5	$88.2
Fair Value of Plan Assets	**720.0**	**3.4**	722.0	3.4
Funded Status	**$(443.2)**	**$(96.2)**	$(324.5)	$(84.8)

The Accumulated Benefit Obligation (“ABO”) for the defined benefit pension plans was $1,080.9 as at December 31, 2011 (2010 – $987.4 million). As at December 31, the aggregate financial position for all plans with an ABO in excess of the Plan assets was as follows:

Pension Plans with ABO in excess of Plan assets	**2011**	2010
millions of Canadian dollars	**Defined benefit pension plans**	Defined benefit pension plans
ABO	**$1,079.3**	$985.9
Fair Value of Plan Assets	**720.0**	722.0
Funded Status	**$(359.3)**	$(263.9)

Balance Sheet

The amounts recognized in the Consolidated Balance Sheets as at December 31 consisted of the following:

	2011		2010	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Current liabilities	**$(4.6)**	**$(4.2)**	$(3.9)	$(5.0)
Long-term liabilities	**(438.5)**	**(92.3)**	(320.2)	(79.8)
Other asset (noncurrent)	**0.3**	**-**	-	-
Amount included in deferred tax asset	**22.9**	**6.7**	13.1	2.4
AOCL after tax adjustment	**502.0**	**11.7**	388.8	6.7
Net amount recognized at end of year	**$82.1**	**$(78.1)**	$77.8	$(75.7)

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCL. The following tables provide detail on the change in AOCL during fiscal 2011 relating to these items; and the composition of the year-end balance:

Accumulated Other Comprehensive Loss millions of Canadian dollars	Actuarial losses (gains)	Past service (gains) costs
Defined Benefit Pension Plans		
Balance, January 1	$402.3	$(0.4)
Amortized in current period	(24.2)	(0.1)
Current year addition to AOCL	154.0	-
Transfer to other regulatory asset (1)	(3.9)	-
Foreign currency translation adjustment	(2.8)	-
Balance, December 31	$525.4	$(0.5)
Non-pension benefits plans		
Balance, January 1	$21.9	$(12.8)
Amortized in current period	(1.6)	1.6
Current year addition to AOCL	8.2	-
Transfer to other regulatory asset (1)	(0.2)	-
Foreign currency translation adjustment	0.9	0.4
Balance, December 31	$29.2	$(10.8)

(1) For MPS, as a result of regulatory accounting, any gain or loss is transferred to regulatory assets and amortized over the same period as the corresponding actuarial gains or losses.

	2011		2010	
Accumulated Other Comprehensive Loss millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Actuarial losses	**$525.4**	**$29.2**	$402.3	$21.9
Past service (gains)	**(0.5)**	**(10.8)**	(0.4)	(12.8)
Total AOCL on a pre-tax basis	**524.9**	**18.4**	401.9	9.1
Less: amount included in deferred tax asset	**(22.9)**	**(6.7)**	(13.1)	(2.4)
Net amount in AOCL after tax adjustment	**$502.0**	**$11.7**	$388.8	$6.7

The amounts in the foregoing table were not recognized in Emera's net periodic benefit cost as at December 31.

Benefit Cost Components

	2011		2010	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Service cost	**15.4**	**2.9**	11.3	2.4
Interest cost	**56.6**	**4.7**	56.6	4.7
Expected return on plan assets	**(56.3)**	**(0.2)**	(55.8)	(0.3)
Current year amortization of:				
Actuarial losses	**24.5**	**1.9**	11.0	1.2
Past service costs (gains)	**0.1**	**(2.0)**	0.2	(2.4)
Total	**40.3**	**7.3**	23.3	5.6

The expected return on plan assets is determined based on the market-related value of plan assets of $803.8 million as at January 1, 2011 (2010 – $775.1 million), adjusted for interest on certain cash flows during the year. The market related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight line basis into the market related value of assets over a five-year period.

Pension Plan Asset Allocations

Emera's investment policy includes discussion regarding the investment philosophy, the level of risk which the Company is prepared to accept with respect to the investment of the Pension Funds, and the basis for measuring the performance of the assets. Central to the policy is the target asset allocation by major asset categories. The objective of the target asset allocation is to diversify risk and to achieve asset returns that meet or exceed the plan's actuarial assumptions. The diversification of assets reduces the inherent risk in financial markets by requiring that assets be spread out amongst various asset classes. Within each asset class, a further diversification is undertaken through the investment in a broad basket of investment grade securities. Emera's target asset allocation is as follows:

Canadian Pension Plans

Asset Class	Target Range at Market		
Short term securities	0%	to	5%
Fixed income	25%	to	40%
Equities:			
Canadian	23%	to	33%
Non-Canadian (World)	32%	to	42%

Non-Canadian Pension Plans

Asset Class	Target Range at Market (weighted average)		
Short term securities	4%	to	10%
Fixed income	22%	to	36%
Equities:			
US	37%	to	55%
Non-US	17%	to	27%

For Bangor Hydro and MPS, the investment of the Non-Canadian pension assets is overseen by their management teams. For GBPC, the investment of Non-Canadian pension assets is overseen by GBPA.

The fair values of investments as at December 31, 2011, by asset category, are as follows:

millions of Canadian dollars	Level 1	%
Cash and cash equivalents	$17.3	2.4%
Equity Securities:		
Canadian equity	162.2	22.5%
US equity	188.4	26.1%
Other equity	89.6	12.4%
Fixed income securities:		
Canadian government	141.7	19.6%
US government	12.5	1.7%
Other government	0.7	0.1%
Corporate debt	109.7	15.2%
Real estate	0.3	-%
Total	$722.4	100%

The fair values of investments as at December 31, 2010, by asset category, are as follows:

millions of Canadian dollars	Level 1	%
Cash and cash equivalents	$9.9	1.4%
Equity Securities:		
Canadian equity	192.7	26.5%
US equity	189.5	26.1%
Other equity	90.4	12.5%
Fixed income securities:		
Canadian government	122.3	16.9%
US government	10.7	1.5%
Other government	0.6	0.1%
Corporate debt	107.6	14.9%
Real estate	0.5	0.1%
Total	$724.2	100%

Refer to Note 1(Y), "*Summary of Significant Accounting Policies – Fair Value Measurement*," for more information on the fair value hierarchy and inputs used to measure fair value. All investments were deemed Level 1 for the years ended December 31, 2011 and 2010.

Investments in Emera or NSPI

As at December 31, 2011 and 2010, the pension funds do not hold any material investments in Emera Incorporated or NSPI securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

Canadian Post Retirement Benefit Plans

There are no assets set aside to pay for the Canadian post-retirement benefit plans. As is common in Canada, post-retirement health benefits are paid from general accounts on a pay as you go basis.

US Post Retirement Benefit Plans

Emera's US subsidiaries currently provide certain post-retirement benefit health care and life insurance benefits for employees retiring after age 55 who meet eligibility requirements. Post-retirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify plans in whole or in part at any time.

Bangor Hydro and MPS provide retiree medical benefits to certain classes of employees. The Company's retiree medical expenses are incorporated into rate filings with its regulators and are recovered through its electric rates to customers.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (MMA) added prescription drug coverage to Medicare, with a 28 percent tax free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. Emera's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit post-retirement health care plan are at least "actuarially equivalent" to the standard drug benefits that are offered under Medicare Part D.

The Company received subsidy payments under Part D for the 2009 and 2010 plan years. Its 2011 Part D subsidy application with the Centers for Medicare and Medicaid Services was approved in December 2010, and the company expects to receive payment later this year.

Emera's target asset allocation for its US Post Retirement Benefits Plan is as follows:

Asset Class	Target Range at Market (weighted average)		
Short term securities	10%	to	50%
Fixed income	0%	to	40%
Equities:			
US	0%	to	60%
Non-US	0%	to	20%

The fair values of investments as at December 31, 2011, by asset category, are as follows:

millions of Canadian dollars	Level 1	%
Cash and cash equivalents	$1.1	32.4%
Equity Securities:		
US equity	1.5	44.1%
Fixed income securities:		
US government	0.8	23.5%
Total	$3.4	100%

The fair values of investments as at December 31, 2010, by asset category, are as follows:

millions of Canadian dollars	Level 1	%
Cash and cash equivalents	$1.1	32.4%
Equity Securities:		
US equity	1.5	44.1%
Fixed income securities:		
US government	0.8	23.5%
Total	$3.4	100%

Refer Note 1(Y), "*Summary of Significant Accounting Policies – Fair Value Measurement*," for more information on the fair value hierarchy and inputs used to measure fair value. All investments were deemed Level 1 for the years ended December 31, 2011 and 2010.

Investments in Emera or NSPI

As at December 31, 2011 and 2010, the assets related to the post-retirement benefit plans do not hold any material investments in Emera Incorporated or NSPI securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

Cash Flows

The following table shows the expected cash flows for defined benefit pension and other post-retirement benefit plans:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefits plans
Expected Employer contributions:		
2012	$73.7	$6.2
Expected Benefit Payments:		
2012	53.2	6.2
2013	56.7	6.9
2014	60.3	7.3
2015	64.4	7.6
2016	68.8	8.0
2017 - 2021	416.9	48.5

Assumptions

The following table shows the assumptions that have been used in accounting for defined benefit pension and other post-retirement benefit plans:

	2011		2010	
(weighted average assumptions)	**Defined benefit pension plans**	**Non-pension benefits plans**	Defined benefit pension plans	Non-pension benefits plans
Benefit obligation – December 31:				
Discount rate	**4.96%**	**4.80%**	5.51%	5.55%
Rate of compensation increase	**3.52%**	**3.50%**	3.75%	3.75%
Health care trend - initial (next year)	**-**	**6.40%**	-	6.70%
- ultimate	**-**	**4.40%**	-	4.50%
- year ultimate reached	**-**	**2014**	-	2014
Benefit cost for year ended December 31:				
Discount rate	**5.51%**	**5.56%**	6.46%	6.25%
Expected long-term return on plan assets	**7.08%**	**-**	7.31%	-
Rate of compensation increase	**3.75%**	**3.75%**	3.75%	3.75%
Health care trend - initial (current year)	**-**	**6.90%**	-	7.53%
- ultimate	**-**	**4.55%**	-	4.51%
- year ultimate reached	**-**	**2014**	-	2014

The expected long-term rate of return on plan assets is based on historical and projected real rates of return for the plan's current asset allocation, and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined. The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

Sensitivity Analysis for Non-Pension Benefits Plans

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2011:

millions of Canadian dollars	Increase	Decrease
Service cost and interest cost	$0.9	$(0.8)
Accumulated post-retirement benefit obligation, December 31	11.0	(9.0)

Amounts to be Amortized in the Next Fiscal Year

The following table shows the amounts from the AOCL which is expected to be recognized as part of the net periodic benefit cost in fiscal 2012:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefits plans
Actuarial (losses)	$(33.1)	$(2.4)
Past service gains	-	1.8
Total	$(33.1)	$(0.6)

Defined Contribution Plan

Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for 2011 was $6.3 million (2010 – $2.6 million).

27. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2011, commitments (excluding pensions and other post-retirement benefits, long-term debt, and ARO) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2012	2013	2014	2015	2016	Thereafter	Total
Purchased power (1)	**$100.3**	$113.4	$117.6	$117.8	$118.0	$1,273.7	$1,840.8
Coal, biomass, oil and natural gas supply	**233.0**	159.9	109.5	63.4	22.4	599.9	$1,188.1
Transportation (2)	**72.5**	29.3	26.8	16.5	2.2	2.7	$150.0
Long-term service agreements (3)	**12.2**	11.3	6.1	5.0	0.5	-	$35.1
Capital projects	**56.3**	3.5	0.6	3.9	-	13.9	$78.2
Leases (4)	**3.9**	3.3	3.2	3.1	2.8	16.0	$32.3
Other	**5.2**	3.8	3.6	3.6	1.0	1.0	$18.2
Total	**$483.4**	324.5	$267.4	$213.3	$146.9	$1,907.2	$3,342.7

(1) Purchased power: annual requirement to purchase 100 percent of electricity production from independent power producers over varying contract lengths up to 25 years.
(2) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on various pipelines.
(3) Long-term service agreements: outsourced management of the Company's computer and communication infrastructure, vegetation management and maintenance of certain generating equipment.
(4) Leases: operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

B. Legal Proceedings

A number of individuals who live in proximity to the Company's Trenton generating station have filed a statement of claim for an unspecified amount against NSPI in respect of emissions from the operation of the plant for the period from 2001 forward. The plaintiffs claim unspecified damages as a result of interference with enjoyment of, or damage to, their property; and adverse health effects they allege were caused by such emissions. The Company has filed a defense to the claim. The outcome of this litigation, and therefore an estimate of any contingent loss, is not determinable.

On October 31, 2011, MF Global Holding Ltd., the parent company of MF Global Inc. ("MFG"), a futures commission merchant used by Emera Energy Services ("Emera Energy") for natural gas and electricity futures filed for Chapter 11 bankruptcy. Emera Energy was able to transfer its open future positions to other brokers; however $5.46 million USD of its posted margin was frozen with MFG and Emera Energy was unable to transfer these funds. Legal proceedings related to the bankruptcy have been initiated and are expected to involve cross-border insolvency proceedings as a result of MFG's global affiliates. Although management expects to recover the majority of the frozen funds, a provision has been recognized and the net amount has been reclassified to "Other long-term assets". The outcome of the bankruptcy proceedings is currently not determinable.

In addition, Emera and its subsidiaries may, from time to time, be involved in legal proceedings, claims and litigations that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. Environment

Emera's activities are subject to a broad range of federal, provincial, state, regional and local laws and environmental regulations, designed to protect, restore, and enhance the quality of the environment including air, water and solid waste. Emera's environmental capital expenditures, excluding AFUDC, based upon present environmental laws and regulations were $67.2 million during 2011 and are estimated to be $439.6 million from 2012 through 2015. Amounts that have been committed are included in "Capital projects" in the commitments included in note 27A. The estimated expenditures do not include costs related to possible changes in the environmental laws or regulations and enforcement policies may be enacted in response to issues such as climate change and other pollutant emissions.

NSPI

NSPI is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters primarily through its utility operations. In addition to imposing continuing compliance obligations, there are laws, regulations and permits authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is material to NSPI. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on NSPI.

Conformance with legislative and NSPI requirements are verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the 2011 and 2010 audits.

Climate Change and Air Emissions

Greenhouse Gas Emissions

NSPI has stabilized, and in recent years, reduced greenhouse gas emissions. This has been achieved by energy efficiency and conservation programs, increased use of natural gas and the addition of new renewable energy sources to the generation portfolio.

Greenhouse gas emissions from NSPI facilities have been capped beginning in 2010 through to 2020. The regulations allow for multi-year compliance periods recognizing the variability in electricity supply sources and demand. Over the decade, the caps will be achieved by a combination of additional renewable generation, import of non-emitting energy, and energy efficiency and conservation.

In 2011, Environment Canada announced proposed regulations for a new national carbon dioxide framework for the electricity sector in Canada. These proposed regulations would apply to new coal-fired electricity generation units; and existing coal-fired electricity generation units that have reached the end of their deemed economic life of forty-five years after commissioning. These proposed regulations will be effective July 1, 2015. Nova Scotia's existing greenhouse gas regulations require reductions in NSPI's emissions similar to those reflected in the federal framework. NSPI is engaged with federal and provincial agencies in reviewing the implications of this federal framework and its alignment with its current operating plans under existing Nova Scotia regulations.

Renewable Energy

The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI’s generation mix. The target date for 5 percent of electricity to be supplied from post-2001 sources of renewable energy, owned by independent power producers, was extended to 2011 from 2010. The target for 2013, which requires an additional 5 percent of renewable energy, is unchanged.

On May 19, 2011 the Nova Scotia Government approved The Electricity Act (Amended) to facilitate the eligibility of energy from the Lower Churchill Project in Labrador as a resource for meeting Nova Scotia's renewable electricity targets. The amendment requires regulations to be developed that increase the percentage of renewable energy in the generation mix from the planned 25 percent in 2015, to 40 percent by 2020.

Mercury, Nitrogen Oxide and Sulphur Dioxide Emissions

NSPI completed a capital program to add sorbent injection to each of the seven pulverized fuel coal units in 2010 at a cost of $17.3 million. This was put in place to address planned reductions in mercury emissions limits, which are set out in the following table:

Year	Mercury Emissions Limit (kg)
2009	168
2010	110
2011 - 2012	100
2013	85
2014 - 2019	65
2020	35

Any mercury emission above 65 kg, between 2010 and 2013, must be offset by lower emissions in the 2014 to 2020 period.

NSPI completed its capital program of retrofitting low nitrogen oxide combustion firing systems on six of its seven pulverized fuel coal units in early 2009 at a cost of $23.3 million. NSPI now meets the nitrogen oxide emission cap of 21,365 tonnes per year established by the Nova Scotia Government effective 2010. These investments, combined with the purchasing of low sulfur coal, allows NSPI to meet the provincial air quality regulations.

NSPI will meet ever-reducing sulphur dioxide emission cap requirements through the use of a blend of net lower sulphur content solid fuel.

Compared to historical levels, NSPI will have reduced mercury emissions by 60 percent effective 2014, nitrogen oxide by 40 percent effective 2009 and sulphur dioxide by 50 percent effective 2010.

Poly Chlorinated Bi-Phenol Transformers

In response to the Canadian Environmental Protection Act 1999, 2008 Poly Chlorinated Bi-Phenol (“PCB”) Regulations to phase out electrical equipment and liquids containing PCBs, NSPI has implemented a program to eliminate transformers and other electrical equipment on its system that do not meet the 2008 PCB Regulations Standard by 2014. In addition, there is a project to phase out the use of pole mount transformers before 2025 including a capital program to destroy all confirmed PCB contaminated pole mount transformers taken out of service through attrition. The combined total cost of these projects is estimated to be $36.5 million and, as at December 31, 2011 approximately $7.8 million (2010 - $5.4 million) has been spent to date. NSPI has recognized an ARO of $20.6 million as at December 31, 2011 (2010 - $13.9 million) associated with the PCB phase-out program.

Maine Utilities

Poly Chlorinated Bi-Phenol Transformers

In response to a Maine environmental regulation to phase out PCB transformers, the Maine Utilities implemented multi-year programs to eliminate transformers on their systems that did not meet the new State environmental guidelines. The Maine Utilities completed their programs in 2011. The cost of testing the transformers was expensed as incurred; replacement transformers and the cost to install those transformers were capitalized. As at December 31, 2011, all transformers have been remediated and are PCB-free in this effort; the total cumulative expenditures associated with the Maine Utilities’ programs at December 31, 2011 was $4.4 million (December 31, 2010 - $3.0 million).

The Barbados Light & Power Company Limited

BLPC implemented a Health Safety Environmental and Quality Management system in 2006 to assist in safeguarding the health and safety of its employees, contractors and customers while ensuring protection of the environment. The Company conducted an environmental impact assessment on its facilities and significant environmental aspects were identified and programs were developed.

D. Principal Risks and Uncertainties

In this section, Emera describes some of the principal risks management believes could materially affect Emera's business, revenues, operating income, net income, net asset or liquidity or capital resources. The nature of risk is such that no list can be comprehensive, and other risks may arise or risks not currently considered material may become material in the future.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach.

Acquisition Risk

The risks associated with Emera's acquisition strategy include the availability of suitable acquisition candidates, obtaining the necessary regulatory approval for any acquisition and assimilating and integrating acquired companies into the Company. In addition, potential difficulties inherent in acquisitions may adversely affect the results of an acquisition. These include delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies from completed transactions.

Emera mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

Regulatory Risk

The Company's rate-regulated subsidiaries are subject to risk in the recovery of costs and investments in a timely manner. The Company manages this regulatory risk through transparent regulatory disclosure, ongoing stakeholder consultation and multi-party engagement on aspects such as utility operations, rate filings and capital plans.

Changes in Environmental Legislation

The Company is subject to regulation by federal, provincial, state, regional, and local authorities with regard to environmental matters primarily related to its utility operations. Changes to climate change and air emissions standards could adversely affect utility operations.

Emera is committed to operating in a manner that is respectful and protective of the environment, and in full compliance with legal requirements and Company policy. Emera and its wholly-owned subsidiaries have implemented this policy through development and application of environmental management systems.

Commodity Prices and Foreign Exchange Rate Fluctuations

A substantial amount of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts. In addition, the adoption and implementation of FAMs in certain subsidiaries has further helped manage this risk.

The Company enters into foreign exchange forward and swap contracts to limit exposure on foreign currency transactions such as fuel purchases and USD revenue streams.

Commercial Relationships

NSPI

For the year ended December 31, 2011, NSPI's five largest customers contributed approximately 13.3 percent (2010 – 14.7 percent) of electric revenues. The loss of a large customer could have a material effect on NSPI's operating revenues. NSPI works to mitigate this risk through the regulatory process.

NSPI's largest customer was granted creditor protection under the Companies' Creditors Arrangement Act ("CCAA"), and suspended operations in September 2011. This customer contributed approximately 6.0 percent (2010 – 7.9 percent) of NSPI's electric revenues for the year ended December 31, 2011. NSPI is working to recover an outstanding balance of $11.6 million through the CCAA claims process, including a claim for set-off against amounts owing from NSPI to the customer that exceeds the amount receivable. The 2012 General Rate Decision, approved by the UARB, provides for any unrecovered non-fuel electric charges in 2012 related to this customer to be deferred and recovered beginning in 2013.

Brunswick Pipeline

Brunswick Pipeline has a 25 year firm service agreement with Repsol Energy Canada ("REC"). The pipeline was used solely in 2011 and 2010 to transport natural gas from the Canaport LNG terminal in Saint John, New Brunswick to the United States border for REC. The risk of non-payment is mitigated as Repsol YPF, S.A ("Repsol"), the parent company of REC, has provided Brunswick Pipeline with a guarantee for all RECs' payment obligations under the firm service agreement. As at December 31, 2011 the net investment in direct financing lease with Repsol was $493.8 million. Repsol is rated investment grade BBB/Baa1; credit ratings and other company information are monitored on an ongoing basis. There is currently no allowance for credit losses related to this agreement.

Bayside Power

Bayside Power sells all of its power during the winter months, November through March, to NB Power in accordance with a long-term purchase power agreement ("PPA"). Revenue from this PPA contributed 46.5 percent (2010 – 48.0 percent) to Bayside Power's electric revenues for the year ended December 31, 2011. The PPA expires March 31, 2021, with an option to renew for an additional five year term, provided both parties consent to the renewal.

Labour Risk

Certain Emera employees are subject to collective labour agreements. Approximately 55 percent of the full-time and term employees at NSPI, BLPC, GBPC, Bangor Hydro, EUS, and MPS are represented by local unions. Approximately 45 percent of the labour force is covered by collective labour agreements that will expire within the next twelve months. Emera seeks to manage this risk through ongoing discussions with local unions.

Weather Risk

Shifts in weather patterns affect electric sales volumes and associated revenues. Extreme weather events generally result in increased operating costs associated with restoring power to customers. Emera responds to significant weather event related outages according to each subsidiary's respective Emergency Services Restoration Plan.

Interest Rate Risk

The Company utilizes a combination of fixed and variable rate debt financing for operations and capital expenditures resulting in an exposure to interest rate risk. The Company seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

E. Collaborative Arrangement

Bangor Hydro

Through Bangor Hydro, the Company is a party to a collaborative arrangement with National Grid Transmission Services Corporation to develop the Northeast Energy Link ("NEL") Project. The cost of development activities, including acquisition of land in the transmission corridor and acquisition of necessary governmental and regulatory permits and approvals, are shared equally between the Company and National Grid. Bangor Hydro has deferred $2.5 million USD of costs associated with the NEL project as at December 31, 2011 (2010 - $2.4 million USD), reported in the Consolidated Balance Sheets in "Other" as part of other assets.

F. Guarantees and Letters of Credit

Emera had the following guarantees and letter of credits as at December 31, 2011:

- NSPI has provided a limited guarantee for the indebtedness of RESL. The guarantee is up to a maximum of $23.5 million. As at December 31, 2011, RESL's indebtedness under the loan agreement was $21.9 million. NSPI holds a security interest in the present and future assets of RESL. For further information refer to Note 1Z.

- Emera has provided a guarantee to the Long Island Power Authority ("LIPA") on behalf of Bear Swamp for Bear Swamp's long-term energy and capacity supply agreement ("PPA") with LIPA, which expires on April 30, 2021. The guarantee is for 50 percent of the relevant obligations under the PPA up to a maximum of $18.6 million USD. As at December 31, 2011, the fair value of the PPA is positive.

- Emera has provided a guarantee to the Bank of Nova Scotia on behalf of Bear Swamp for Bear Swamp's interest rate swaps entered into between Bear Swamp and the Bank of Nova Scotia which expires on May 9, 2012. The guarantee is for 50 percent of the relevant obligations up to a maximum of $1.0 million USD. In the event Emera was required to make a payment to the Bank of Nova Scotia under this guarantee, the guarantee provides that Emera is able to seek recovery from Bear Swamp's creditors after Bear Swamp has paid its debts in full. As at December 31, 2011, the fair value of that agreement is positive.

- At the request of Emera and its subsidiaries, a financial institution has issued standby letters of credit in the amount of $11.4 million for the benefit of third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one year term and are renewed annually as required.

- A financial institution has issued a standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2012 and is renewed annually. The amount committed as at December 31, 2011 was $22.5 million.

- A financial institution has issued a standby letter of credit to secure obligations under an unfunded pension plan in BHE. The letter of credit is renewed annually in October. The amount committed as at December 31, 2011 was $2.2 million USD.

- A financial institution has been issued direct pay letters of credit totaling $23.9 million USD to secure principal and interest payments related to Maine Public Utilities Financing Bank bonds issued on behalf of MPS, related to qualifying distribution assets.

No liability has been recognized in the consolidated balance sheets related to any potential obligation under these guarantees and letters of credits.

28. COMMON STOCK

Authorized: Unlimited number of non-par value common shares.

		2011		2010
Issued and outstanding:	**Millions of shares**	**Millions of Canadian dollars**	Millions of shares	Millions of Canadian dollars (adjusted)
Balance, January 1	**114.62**	**$1,137.8**	112.98	$1,097.9
Issuance of common stock	**6.36**	**196.0**	-	-
Issued for cash under Purchase Plans at market rate	**1.40**	**42.8**	1.32	34.4
Discount on shares purchased under Dividend Reinvestment Plan	**-**	**(1.8)**	-	(1.5)
Options exercised under senior management share option plan	**0.45**	**8.8**	0.32	6.0
Stock-based compensation	**-**	**1.4**	-	1.0
Balance, December 31	**122.83**	**$1,385.0**	114.62	$1,137.8

In March 2011, Emera issued 6,359,500 common shares, which included the exercise of the over-allotment option of 829,500 common shares. The shares were issued at $31.70 per share for net proceeds after-tax and issuance costs of $196.0 million.

As at December 31, 2011, there were 3.4 million (2010 – 3.8 million) common shares reserved for issuance under the senior management stock option plan, and 0.3 million (2010 – 0.5 million) common shares reserved for issuance under the employee common share purchase plan. The issuance of common shares under the current or proposed common share compensation arrangements will not exceed ten percent of Emera's outstanding common shares.

29. STOCK-BASED COMPENSATION

EMPLOYEE COMMON STOCK PURCHASE PLAN AND COMMON SHAREHOLDERS DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN ("Purchase Plans")

The Company has an Employee Common Share Purchase Plan to which employees make cash contributions for the purpose of purchasing common shares. The Company also contributes to the plan a percentage of the employees' contributions. The plan allows the reinvestment of dividends. The maximum aggregate number of common shares reserved for issuance under this plan is 2.0 million common shares.

The Company uses the fair value based method to measure the compensation expense related to its employee purchase plan. Compensation cost recognized for the year ended December 31, 2011 was $0.7 million (2010 – $0.7 million) and is included in "Operating, maintenance and general".

The Company also has a Common Shareholders Dividend Reinvestment and Share Purchase Plan ("Dividend Reinvestment Plan"), which provides an opportunity for shareholders to reinvest dividends and to make cash contributions for the purpose of purchasing common shares. Effective September 25, 2009, Emera changed its Dividend Reinvestment Plan to provide for a discount of up to 5% from the average market price of Emera's common shares for common shares purchased in connection with the reinvestment of cash dividends under the Plans.

STOCK-BASED COMPENSATION PLANS

Stock Option Plan

The Company has a stock option plan that grants options to senior management of the Company for a maximum term of ten years. The option price of the stock options is the closing market price of the stocks on the day before the option is granted. The maximum aggregate number of shares issuable under this plan is 6.7 million shares.

All options granted to date are exercisable on a graduated basis with up to 25 percent of options exercisable on the first anniversary date and in further 25 percent increments on each of the second, third and fourth anniversaries of the grant. If an option is not exercised within ten years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The total number of stocks to be optioned to any optionee shall not exceed five percent of the issued and outstanding common stocks on the date the option is granted.

If, before the expiry of an option in accordance with its terms, the optionee ceases to be an eligible person due to retirement or termination for other than just cause, such option may, subject to the terms thereof and any other terms of the plan, be exercised at any time within the 24 months following the date the optionee retires, but in any case prior to the expiry of the option in accordance with its terms.

If, before the expiry of an option in accordance with its terms, the optionee ceases to be an eligible person due to employment termination for just cause, resignation or death, such option may, subject to the terms thereof and any other terms of the plan, be exercised at any time within the six months following the date the optionee is terminated, resigns, or dies, as applicable, but in any case prior to the expiry of the option in accordance with its terms.

The Company uses the fair value based method to measure the compensation expense related to its stock-based compensation and recognizes the expense over the vesting period on a straight-line basis. The fair value of stock option awards granted was estimated on the date of grant using a Black-Scholes valuation model. The expected term of the option awards is calculated based on historical exercise behavior and represents the period of time that options are expected to be outstanding. The risk-free interest rate is based on the Bank of Canada seven-year government bond yields. The expected dividend yield incorporates current dividend rates as well as historical dividend increase patterns. Emera's expected stock price volatility was estimated using its three-year historical volatility.
The following table shows the weighted-average fair values per stock option along with the assumptions incorporated into the valuation models for options granted:

	2011	2010
Weighted average fair value per option	**$19.96**	$19.38
Expected term	**7 years**	7 years
Risk-free interest rate	**3.88%**	3.92%
Expected dividend yield	**4.89%**	4.91%
Expected volatility	**14.32%**	14.16%

A summary of stock option activity for the year ended December 31, 2011 and information related to outstanding and exercisable stock options as at December 31, 2011 is presented in the following table.

	Stock Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (millions of Canadian dollars)
Outstanding as at December 31, 2010	2,146,078	$21.02	6.7	$22.2
Granted	217,300	32.06		0.2
Exercised	(448,725)	19.45		6.1
Forfeited	(83,256)	27.03		0.5
Outstanding as at December 31, 2011	1,831,397	$22.44	6.4	$19.4
Exercisable as at December 31, 2011	1,161,397	$20.57		$14.5

Compensation cost recognized for stock options for the year ended December 31, 2011 was $0.7 million (2010 – $0.7 million) and is included in "Operating, maintenance and general".

As at December 31, 2011, the compensation cost related to unvested and outstanding stock options was $0.9 million and expected to be recognized over a weighted-average period of 3.3 years (2010 – $1.0 million, 3.3 years). Cash received from option exercises for the year ended December 31, 2011 was $8.7

million (2010 – $6.3 million). The total intrinsic value of options exercised for the year ended December 31, 2011 was $6.1 million (2010 – $4.1 million). The range of exercise prices for the options outstanding as at December 31, 2011 was $15.73 to $32.06 (2010 – $13.70 to $31.02).

Share Unit Plans

The Company has deferred share unit ("DSU") and performance share unit ("PSU") plans. The DSU and PSU liabilities are marked-to-market at the end of each period based on the common share price at the end of the period.

Deferred Share Unit Plan

Under the Directors' DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera's common shares referred to as the Dividend Reinvestment Plan ("DRIP"), the Director's DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns, or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50% of the value of their actual annual incentive award (25% in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares, referred to as DRIP. Following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Payments are usually made in cash. At the sole discretion of the Management Resources and Compensation Committee ("MRCC"), payments may be made in the form of actual shares.

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or to achieve certain corporate objectives.

A summary of the activity related to employee and director DSU's for the year ended December 31, 2011 is presented in the following table:

	Employee DSU	Weighted Average Grant Date Fair Value	Director DSU	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2010	338,322	$20.71	149,943	$23.19
Granted including DRIP	44,537	31.15	46,161	32.31
Exercised	(19,938)	22.27	-	-
Outstanding as at December 31, 2011	362,921	$21.91	196,104	$25.34

Compensation cost recognized for employee and director DSU for the year ended December 31, 2011 was $1.2 million (2010 – $3.6 million). Compensation cost capitalized for employee and director DSU for the year ended December 31, 2011 was $0.1 million (2010 – nil). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2011 were $0.4 million (2010 – $1.1 million).

Performance Share Unit Plan

Under the PSU plan, executive and senior employees are eligible for long-term incentives payable through the PSU plan. PSUs are granted annually for three-year overlapping performance cycles. PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Dividend equivalents are awarded and are used to purchase additional PSUs, also referred to as DRIP. The PSU value varies according to the Emera common share market price and corporate performance.

PSUs vest at the end of the three-year cycle and will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and will be pro-rated in the case of retirement, disability or death.

A summary of the activity related to employee PSU's for the year ended December 31, 2011 is presented in the following table:

	Employee PSU	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2010	362,261	$25.95
Granted including DRIP	140,340	31.18
Exercised	(136,345)	23.13
Forfeited	(11,798)	28.96
Outstanding as at December 31, 2011	354,458	$29.01

Compensation cost recognized for the PSU plan for the year ended December 31, 2011 was $3.7 million (2010 – $6.1 million). Compensation cost capitalized for employee PSU for the year ended December 31, 2011 was $0.2 million (2010 – nil). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2011 were $1.2 million (2010 – $1.9 million).

Non-Vested Stock-Based Compensation Plans

For the year ended December 31, 2011, a summary of activity from the different plans is presented in the following table:

	Stock Option Plan		Share Unit Plan: DSU Plan		Share Unit Plan: PSU Plan	
	Number of options	Weighted Average Grant Date Fair Value	Number of share units	Weighted Average Grant Date Fair Value	Number of share units	Weighted Average Grant Date Fair Value
Non-vested shares as at December 31, 2010	889,528	$22.86	20,797	$21.70	225,916	$27.65
Granted	217,300	32.06	682	31.08	140,340	31.18
Vested	(353,572)	22.16	(10,767)	21.14	(125,496)	23.79
Forfeited	(83,256)	27.03	-	-	(11,798)	28.96
Non-vested shares as at December 31, 2011	670,000	$30.38	10,712	$22.85	228,962	$31.86

The total fair value of shares vested for all the plans was $60.6 million for the year ended December 31, 2011 (2010 - $58.3 million). The weighted-average grant date fair value of shares, granted for all the plans, for the year ended December 31, 2011 was $23.42 (2010 - $21.69).

Fully-Vested Stock-Based Compensation Plans

		Share Unit Plan	
	Stock Option Plan	**DSU Plan**	**PSU Plan**
Outstanding			
Number of options/share units	1,831,397	548,313	125,497
Weighted-average exercise price of options	$22.44	-	-
Aggregate intrinsic value/fair value of options/share units	$19,411,216	$18,116,262	$4,146,421
Weighted-average remaining contractual terms of option/share units	6.4 years	-	-
Currently Exercisable			
Number of options/share units	1,161,397	-	-
Weighted-average exercise price of options	$20.57	-	-
Aggregate intrinsic value/fair value of options/share units	$14,487,594	-	-
Weighted-average remaining contractual terms of option/share units	5.1 years	-	-

30. CUMULATIVE PREFERRED STOCK

Authorized:
Unlimited number of First Preferred shares, issuable in series.
Unlimited number of Second Preferred shares, issuable in series.

		2011		2010
Issued and outstanding:	**Millions of shares**	**Millions of dollars**	Millions of shares	Millions of dollars
Balance	**6.0**	**$146.7**	6.0	$146.7

In June 2010, Emera issued six million 4.40% Cumulative Five-Year Rate Reset First Preferred Stock, Series A ("First Preferred Stock, Series A"). The $150 million First Preferred Stock, Series A were issued at $25.00 per share for net after-tax and transaction costs proceeds of $146.7 million.

As the First Preferred Shares, Series A are neither redeemable at the option of the shareholder nor have a mandatory redemption date, they are classified as equity and the associated dividends will be deducted on the consolidated statements of earnings immediately before arriving at "Net earnings attributable to common shareholders" and will be shown on the consolidated statement of equity as a deduction from retained earnings.

The First Preferred Shares, Series A are entitled to receive fixed cumulative preferred cash dividends in the amount of $1.10 per share per annum for each year up to and including May 15, 2015. For each five-year period after this date, the holders of First Preferred Shares, Series A are entitled to receive reset fixed cumulative preferred cash dividends. The reset annual dividends per share will be determined by multiplying the $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 1.84 percent.

The holders of First Preferred Shares, Series A will have the right, at their option, to convert their shares into an equal number of Cumulative Floating Rate First Preferred Shares, Series B of the Company on August 15, 2015 and every five years thereafter.

The First Preferred Shares, Series B have the same characteristics as the Series A shares, with the exception of the calculation of the floating dividend rate for the Series B shares being the sum of the T-bill rate plus 1.84 percent.

The holders of the First Preferred Shares, Series B will have the right, at their option, to convert their shares into an equal number of Series A shares of the Company on August 15, 2020 and every five years thereafter.

On August 15, 2015 and August 15, 2020 respectively and on August 15 every five years thereafter, the Company has the right to redeem for cash the outstanding First Preferred Shares, Series A or B in whole or in part at a price of $25 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

The First Preferred Shares of each series rank on a parity with the First preferred Shares of every other series and are entitled to a preference over a the Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares will be entitled to attend any meeting of shareholders of the Company and to vote at any such meeting.

31. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of accumulated other comprehensive income (loss) as at December 31, 2011 and 2010 are as follows:

			2011			2010
millions of Canadian dollars	**Opening Balance**	**Net Change**	**Ending Balance**	Opening Balance	Net Change	Ending Balance
(Losses) gains on derivatives recognized as Cash Flow Hedges	**$(2.2)**	**$(8.7)**	**$(10.9)**	$(8.3)	$6.1	$(2.2)
Net change in unrecognized pension and post-retirement benefit costs	**(394.5)**	**(122.9)**	**(517.4)**	(281.1)	(113.4)	(394.5)
Unrealized loss on available-for-sale investments	**(1.2)**	**(0.3)**	**(1.5)**	(1.0)	(0.2)	(1.2)
Unrealized (loss) gain on translation of self-sustaining foreign operations	**(166.3)**	**24.4**	**(141.9)**	(135.8)	(30.5)	(166.3)
Accumulated Other Comprehensive Loss	**$(564.2)**	**$(107.5)**	**$(671.7)**	$(426.2)	$(138.0)	$(564.2)

32. NON-CONTROLLING INTEREST IN SUBSIDIARIES

Non-controlling interest in subsidiaries as at December 31 consisted of the following:

millions of Canadian dollars	**2011**	2010
Preferred shares of NSPI	**$132.2**	$132.2
Preferred shares of Bangor Hydro	**0.4**	0.5
BLPC	**60.6**	-
ICDU	**31.3**	21.7
	$224.5	$154.4

Preferred shares of NSPI:

Authorized:
Unlimited number of First Preferred shares, issuable in series.
Unlimited number of Second Preferred shares, issuable in series.

		2011		2010
Issued and outstanding:	**Millions of shares**	**Millions of dollars**	Millions of shares	Millions of dollars
Balance	**5.4**	**$132.2**	5.4	$132.2

Series D First Preferred Stock:

On and after October 15, 2015, Series D First Preferred Stock is redeemable by NSPI, in whole at any time or in part from time to time at $25 per share plus accrued and unpaid dividends. NSPI also has the option, commencing October 15, 2015, to exchange the Series D First Preferred Stock into Emera common stock determined by dividing $25 by the greater of $2 and the market price of the Emera common stock.

Commencing on and after January 15, 2016, with prior notice and prior to any dividend payment date, each Series D First Preferred Stock will be exchangeable at the option of the holder into fully paid and freely tradable Emera common stock determined by dividing $25 by the greater of $2 and the market price of the Emera common stock, subject to the right of NSPI to redeem such stock for cash or to cause the holders of such stock to sell on the exchange date all or any part of such stock to substitute purchasers found by NSPI. NSPI will pay all accrued and unpaid dividends to the exchange date.

Each Series D First Preferred Stock is entitled to a $1.475 per share per annum fixed cumulative preferential dividend, as and when declared by the Board of Directors, accruing from the date of issue and payable quarterly on the fifteenth day of January, April, July and October of each year.

The First Preferred Shares of each series rank on a parity with the First preferred Shares of every other series issued by NSPI and are entitled to a preference over NSPI's Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of NSPI in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event NSPI fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of NSPI's First Preferred Shares will be entitled to attend any meeting of shareholders of NSPI and to vote at any such meeting.

33. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera purchased natural gas transportation capacity from M&NP, an investment under significant influence of the Company, totaling $47.3 million (2010 – $55.1 million) for the year ended December 31, 2011. The amount is recognized in "Regulated fuel for generation and purchased power" or netted against energy marketing margin in "Non-regulated operating revenues" and is measured at the exchange amount. As at December 31, 2011, the amount payable to the related party was $3.3 million (2010 – $3.9 million), and is under normal interest and credit terms.

34. QUARTERLY DATA (UNAUDITED)

For the quarter ended millions of Canadian dollars (except per share amounts)	**Q4 2011**	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Total operating revenues	**$512.0**	$496.1	$501.7	$554.6	$408.9	$394.0	$364.7	$438.5
Net income	**49.4**	48.3	34.2	127.5	23.6	45.4	50.7	79.6
Net income attributable to common shareholders	**46.8**	40.8	29.9	123.6	24.1	40.3	48.5	77.8
Earnings Per Share - basic	**$0.38**	$0.33	$0.24	$1.06	$0.21	$0.35	$0.43	$0.68
Earnings Per Share - diluted	**$0.38**	$0.33	$0.24	$1.03	$0.21	$0.35	$0.42	$0.67
Dividends per common share declared	**-**	$0.6625	$0.3250	$0.3250	-	$0.6075	$0.2825	$0.2725

35. USGAAP TRANSITION

ADOPTION OF USGAAP

In February 2008, the Canadian Institute of Chartered Accountants ("CICA") announced that CGAAP for publically accountable enterprises would be replaced by IFRS for fiscal years beginning on or after January 1, 2011. In Q4 2009, due primarily to the continued uncertainty around the applicability of a rate-regulated accounting standard under IFRS, management reviewed the option of adopting USGAAP instead of IFRS. During Q1 2010, the Company's Board of Directors approved the transition to USGAAP as recommended by management. The adoption of USGAAP has been made on a retrospective basis with restatement of prior periods' financial statements to reflect USGAAP requirements in effect at that time.

For annual reporting purposes, the transition date to USGAAP is January 1, 2010, which is the commencement of the 2010 comparative period to the Company's 2011 financial statements.

As a result of NSPI's decision to transition to USGAAP, effective January 1, 2011 there was an amendment to NSPI's regulated accounting policy for financial instruments and hedges which was approved by the UARB. The effects of this amendment were applied retrospectively, in accordance with that policy, without restatement of prior period income. The adjustments related to the amended accounting policy have been included with the adjustments as described further in this note.

Measurement, classification and disclosure differences arising out of the Company's election to adopt USGAAP are presented below. With respect to measurement and classification differences, Section I "USGAAP differences", presents quantitative reconciliations of balance sheets, income statements and statements of cash flows, previously presented in accordance with CGAAP, to the respective amounts and classifications under USGAAP, together with descriptions of the various significant measurement and classification differences arising from the adoption of USGAAP. Balance sheet reconciliations are presented as at January 1, 2010 and December 31, 2010, representing the commencement and ending dates of the comparative financial year to 2011. Income statement and statement of cash flow reconciliations are presented for the three, six and nine months ended March 31, 2010, June 30, 2010, and September 30, 2010, respectively and for the year ended December 31, 2010, which are periods that will be presented as comparatives to 2011 financial reporting.

In addition, USGAAP requires certain disclosures of financial information, significant to the Company, that are in addition to the required disclosure under CGAAP.

Except as otherwise disclosed in this note, the change in basis of accounting from CGAAP to USGAAP did not materially impact accounting policies or disclosures. Reference should be made to the previously filed CGAAP financial statements as at and for the year ended December 31, 2010 for additional information on CGAAP accounting policies and practices.

The following table summarizes the increases (decreases) to total assets:

As at millions of Canadian dollars	Notes	January 1 2010	December 31 2010
Total assets – CGAAP		$5,277.5	$6,321.8
Accounting for joint ventures	A	(76.4)	(75.4)
Offsetting	B	(0.9)	-
Income taxes	C	17.2	(136.4)
Hedging	F	99.1	42.3
Issue costs	G	16.4	18.9
Business combinations	J	(0.2)	7.7
Pension and other post-retirement benefits	K	(85.1)	(100.4)
Other		(0.3)	0.5
Total transition adjustments		(30.2)	(242.8)
Total assets – USGAAP		$5,247.3	$6,079.0

The following table summarizes the increases (decreases) to total liabilities:

As at millions of Canadian dollars	Notes	January 1 2010	December 31 2010
Total liabilities – CGAAP		$3,739.5	$4,527.5
Accounting for joint ventures	A	(76.5)	(75.9)
Offsetting	B	(0.9)	-
Income taxes	C	17.0	(131.2)
Hedging	F	51.9	49.8
Issue costs	G	17.5	20.0
Pension and other post-retirement benefits	K	199.3	291.8
Preferred stock of NSPI	P	(134.0)	(134.1)
Other		(0.3)	(0.3)
Total transition adjustments		74.0	20.1
Total liabilities – USGAAP		$3,813.5	$4,547.6

The following table summarizes the increases (decreases) to net income:

For the millions of Canadian dollars	3 months ended March 31 2010 (unaudited)	6 months ended June 30 2010 (unaudited)	9 months ended September 30 2010 (unaudited)	Year ended December 31 2010
Net income attributable to common shareholders – CGAAP	$77.1	$106.7	$151.5	$191.1
Note C – Income taxes	1.2	1.0	(3.9)	(5.0)
Note F – Hedging	(0.7)	(4.9)	(5.4)	(6.0)
Note J – Business combinations	-	22.5	22.3	8.4
Note K – Pension and other post-retirement benefits	0.6	1.1	1.7	2.3
Note P – Preferred stock of NSPI	-	0.1	0.1	0.1
Note R – Stock-based compensation	(0.1)	(0.1)	(0.2)	(0.2)
Note S – Foreign currency translation	(0.4)	(0.4)	(0.1)	(0.3)
Other	0.1	0.3	0.6	0.3
Total transition adjustments	0.7	19.6	15.1	(0.4)
Net income attributable to common shareholders – USGAAP	$77.8	$126.3	$166.6	$190.7
Earnings per common share – basic – CGAAP	$0.68	$0.94	$1.33	$1.68
Effect of USGAAP transition	-	0.17	0.13	(0.01)
Earnings per common share – basic – USGAAP	$0.68	$1.11	$1.46	$1.67

USGAAP differences

The reconciliations of the January 1, 2010 and December 31, 2010 Balance Sheets from CGAAP to USGAAP are as follows:

As at January 1, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Assets				
Current assets				
Cash and cash equivalents	A	$21.8	$(1.6)	$20.2
Restricted cash	A	1.0	(1.0)	-
Receivables, net	A, B	413.1	(4.8)	408.3
Income taxes receivable		4.0	-	4.0
Inventory		174.5	-	174.5
Deferred income taxes	C	46.7	(23.6)	23.1
Derivatives in a valid hedging relationship	D	26.3	(26.3)	-
Held-for-trading derivatives	D	13.1	(13.1)	-
Derivative instruments	D	-	39.3	39.3
Regulatory assets	E, F	-	131.7	131.7
Prepaid expenses	A	7.4	(0.2)	7.2
Other current assets	G, H	-	3.2	3.2
Total current assets		707.9	103.6	811.5
Property, plant and equipment	A, C, I, J	2,933.7	170.5	3,104.2
Construction work-in-progress	I	220.2	(220.2)	-
		3,153.9	(49.7)	3,104.2
Other assets				
Deferred income taxes	C	4.4	61.8	66.2
Derivatives in a valid hedging relationship	D	30.9	(30.9)	-
Held-for-trading derivatives	D	30.7	(30.7)	-
Derivative instruments	A, D	-	45.4	45.4
Regulatory assets	C, E, F, J, K	-	278.8	278.8
Net investment in direct financing lease	F	476.9	3.2	480.1
Investments subject to significant influence	A	218.4	(2.1)	216.3
Available-for-sale investment	M	47.3	(46.3)	1.0
Goodwill		87.6	-	87.6
Intangibles	L	92.1	(92.1)	-
Other	A, C, E, G, H, K, L, M	427.4	(271.2)	156.2
Total other assets		1,415.7	(84.1)	1,331.6
Total assets		$5,277.5	$(30.2)	$5,247.3

As at January 1, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Liabilities and Equity				
Current liabilities				
Short-term debt		$300.3	-	$300.3
Current portion of long-term debt	A	108.1	(1.6)	106.5
Accounts payable	A, B, N	-	218.3	218.3
Accounts payable and accrued charges	N	305.9	(305.9)	-
Income taxes payable	C	2.3	1.2	3.5
Dividends payable	O	1.7	(1.7)	-
Derivatives in a valid hedging relationship	D	61.0	(61.0)	-
Held-for-trading derivatives	D	18.6	(18.6)	-
Derivative instruments	A, D	-	78.2	78.2
Regulatory liabilities	C, E, F	-	50.0	50.0
Pension and post-retirement liabilities	K	-	9.2	9.2
Other current liabilities	C, H, N, O, P	-	91.7	91.7
Total current liabilities		797.9	59.8	857.7
Long-term liabilities				
Long-term debt	A, G, P	2,318.4	(45.7)	2,272.7
Deferred income taxes	C, K	194.1	(67.9)	126.2
Derivatives in a valid hedging relationship	D	25.7	(25.7)	-
Held-for-trading derivatives	D	15.8	(15.8)	-
Derivative instruments	A, D	-	35.5	35.5
Regulatory liabilities	C, E, F	-	91.5	91.5
Asset retirement obligations		104.5	-	104.5
Pension and post-retirement liabilities	K	-	292.4	292.4
Other long-term liabilities	A, E, H, K	148.1	(115.1)	33.0
Preferred shares issued by a subsidiary	P	135.0	(135.0)	-
Total long-term liabilities		2,941.6	14.2	2,955.8
Non-controlling interest	Q	32.1	(32.1)	-
Equity				
Common stock	R	1,096.7	1.2	1,097.9
Contributed surplus	R	3.6	(0.6)	3.0
Accumulated other comprehensive loss	A, C, F, K, S	(186.7)	(239.5)	(426.2)
Retained earnings	F, G, J, K, P, R, S	592.3	2.5	594.8
Total Emera Incorporated equity		1,505.9	(236.4)	1,269.5
Non-controlling interest in subsidiaries	P, Q	-	164.3	164.3
Total equity		1,505.9	(72.1)	1,433.8
Total liabilities and equity		$5,277.5	$(30.2)	$5,247.3

As at December 31, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Assets				
Current assets				
Cash and cash equivalents	A	$9.4	$(2.1)	$7.3
Restricted cash	A	59.6	(1.0)	58.6
Receivables, net	A	396.5	(3.6)	392.9
Income taxes receivable	C	43.4	(6.4)	37.0
Inventory		177.8	-	177.8
Deferred income taxes	C	28.2	(14.5)	13.7
Derivatives in a valid hedging relationship	D	28.4	(28.4)	-
Held-for-trading derivatives	D	22.1	(22.1)	-
Derivative instruments	A, D	-	49.7	49.7
Regulatory assets	E, F	-	90.5	90.5
Prepaid expenses	A	9.8	(0.3)	9.5
Other current assets	G, H	-	3.1	3.1
Total current assets		775.2	64.9	840.1
Property, plant and equipment	A, C, I, J	3,456.1	286.5	3,742.6
Construction work-in-progress	I	333.0	(333.0)	-
		3,789.1	(46.5)	3,742.6
Other assets				
Deferred income taxes	C	12.9	18.2	31.1
Derivatives in a valid hedging relationship	D	26.1	(26.1)	-
Held-for-trading derivatives	D	15.3	(15.3)	-
Derivative instruments	A, D	-	36.0	36.0
Regulatory assets	C, E, F, K	-	354.9	354.9
Net investment in direct financing lease	F	488.2	3.3	491.5
Investments subject to significant influence	A, C, J	238.9	7.1	246.0
Available-for-sale investment	M	47.0	(46.2)	0.8
Goodwill	J, K	178.9	(11.5)	167.4
Intangibles	L	98.1	(98.1)	-
Other	A, C, E, G, H, J, K, L, M	652.1	(483.5)	168.6
Total other assets		1,757.5	(261.2)	1,496.3
Total assets		$6,321.8	$(242.8)	$6,079.0

As at December 31, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Liabilities and Equity				
Current liabilities				
Short-term debt	G	$81.3	$0.4	$81.7
Current portion of long-term debt	A	12.7	(2.1)	10.6
Accounts payable	A, N	-	293.9	293.9
Accounts payable and accrued charges	N	399.6	(399.6)	-
Income taxes payable	C	1.1	(0.9)	0.2
Deferred income taxes	C	-	8.5	8.5
Dividends payable	O	1.8	(1.8)	-
Derivatives in a valid hedging relationship	D	8.6	(8.6)	-
Held-for-trading derivatives	D	31.1	(31.1)	-
Derivative instruments	A, D	-	36.8	36.8
Regulatory liabilities	C, E, F	-	55.0	55.0
Pension and post-retirement liabilities	K	-	8.9	8.9
Other current liabilities	A, C, H, N, O, P	-	110.3	110.3
Total current liabilities		536.2	69.7	605.9
Long-term liabilities				
Long-term debt	A, G, P	3,153.7	(38.4)	3,115.3
Deferred income taxes	C, K	359.8	(191.3)	168.5
Derivatives in a valid hedging relationship	D	21.3	(21.3)	-
Held-for-trading derivatives	D	18.0	(18.0)	-
Derivative instruments	A, D	-	28.9	28.9
Regulatory liabilities	C, E, F	-	65.2	65.2
Asset retirement obligations		141.8	-	141.8
Pension and post-retirement liabilities	K	-	400.0	400.0
Other long-term liabilities	E, H, K	161.7	(139.7)	22.0
Preferred shares issued by a subsidiary	P	135.0	(135.0)	-
Total long-term liabilities		3,991.3	(49.6)	3,941.7
Non-controlling interest	Q	20.7	(20.7)	-
Equity				
Common stock	R	1,136.5	1.3	1,137.8
Preferred stock		146.7	-	146.7
Contributed surplus	R	3.7	(0.5)	3.2
Accumulated other comprehensive loss	A, C, F, J, K, Q, S	(164.7)	(399.5)	(564.2)
Retained earnings	C, F, G, J, K, P, R, S	651.4	2.1	653.5
Total Emera Incorporated equity		1,773.6	(396.6)	1,377.0
Non-controlling interest in subsidiaries	P, Q	-	154.4	154.4
Total equity		1,773.6	(242.2)	1,531.4
Total liabilities and equity		$6,321.8	$(242.8)	$6,079.0

The adjustments to January 1, 2010 and December 31, 2010 equity are as follows:

As at January 1, 2010 millions of Canadian dollars	Common Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest in Subsidiaries	Total Equity
CGAAP	$1,096.7	$3.6	$(186.7)	$592.3	-	$1,505.9
Note A – Accounting for joint ventures	-	-	0.1	-	-	0.1
Note C – Income taxes	-	-	0.2	-	-	0.2
Note F – Hedging	-	-	36.6	10.6	-	47.2
Note G – Issue costs	-	-	-	(1.1)	-	(1.1)
Note J – Business combinations	-	-	-	(0.2)	-	(0.2)
Note K – Pension and other post-retirement benefits	-	-	(277.6)	(6.8)	-	(284.4)
Note P – Preferred stock of NSPI	-	-	-	1.8	$132.2	134.0
Note Q – Non-controlling interest in subsidiaries	-	-	-	-	32.1	32.1
Note R – Stock-based compensation	1.2	(0.6)	-	(0.6)	-	-
Note S – Foreign currency translation	-	-	1.2	(1.2)	-	-
Total transition adjustments	1.2	(0.6)	(239.5)	2.5	164.3	(72.1)
USGAAP	$1,097.9	$3.0	$(426.2)	$594.8	$164.3	$1,433.8

As at December 31, 2010 millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interest in Subsidiaries	Total Equity
CGAAP	$1,136.5	$146.7	$3.7	$(164.7)	$651.4	-	$1,773.6
Note A – Accounting for joint ventures	-	-	-	0.5	-	-	0.5
Note C – Income taxes	-	-	-	0.2	(5.4)	-	(5.2)
Note F – Hedging	-	-	-	(12.1)	4.6	-	(7.5)
Note G – Issue costs	-	-	-	-	(1.1)	-	(1.1)
Note J – Business combinations	-	-	-	(0.5)	8.2	-	7.7
Note K – Pension and other post-retirement benefits	-	-	-	(387.9)	(4.3)	-	(392.2)
Note P – Preferred stock of NSPI	-	-	-	-	1.9	$132.2	134.1
Note Q – Non-controlling interest in subsidiaries	-	-	-	(1.5)	-	22.2	20.7
Note R – Stock-based compensation	1.3	-	(0.5)	-	(0.8)	-	-
Note S – Foreign currency translation	-	-	-	1.6	(1.6)	-	-
Other	-	-	-	0.2	0.6	-	0.8
Total transition adjustments	1.3	-	(0.5)	(399.5)	2.1	154.4	(242.2)
USGAAP	$1,137.8	$146.7	$3.2	$(564.2)	$653.5	$154.4	$1,531.4

The statements of income for the 2010 periods reconciled from CGAAP to USGAAP are as follows:

For the three months ended March 31, 2010 millions of Canadian dollars (except per share amounts) (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Operating revenues				
Electric	T	$412.1	$(412.1)	-
Finance income from direct finance lease	T	14.2	(14.2)	-
Other	T	3.8	(3.8)	-
Regulated	F, T, U	-	395.4	$395.4
Non-regulated	A, T, U	-	43.1	43.1
Total operating revenues		430.1	8.4	438.5
Operating expenses				
Regulated fuel for generation and purchased power	U, V	217.7	(23.7)	194.0
Regulated fuel adjustment		(39.4)	-	(39.4)
Non-regulated fuel for generation and purchase power	A, V	-	23.1	23.1
Non-regulated direct costs	U	-	8.2	8.2
Operating, maintenance and general	A, K, R, U	76.7	0.8	77.5
Provincial, state and municipal taxes	A	12.4	(0.4)	12.0
Depreciation and amortization	A, C, X	42.3	5.0	47.3
Regulatory amortization	X	5.4	(5.4)	-
Total operating expenses		315.1	7.6	322.7
Income from operations		115.0	0.8	115.8
Income from equity investments	A	2.3	(1.6)	0.7
Other income (expenses), net	A, F, S, T, U, W, Y	-	(1.8)	(1.8)
Financing charges	P, W, Y	43.2	(43.2)	-
Interest expense, net	A, C, U, W, Y	-	37.6	37.6
Income before provision for income taxes		74.1	3.0	77.1
Income tax expense (recovery)	A, C	(2.8)	0.3	(2.5)
Net income		76.9	2.7	79.6
Non-controlling interest in subsidiaries	P	(0.2)	2.0	1.8
Net income attributable to common shareholders		$77.1	$0.7	$77.8
Weighted average number of shares (in millions)				
Basic		113.2	0.4	113.6
Diluted		120.0	-	120.0
Earnings per common share				
Basic		$0.68	-	$0.68
Diluted		$0.66	$0.01	$0.67
Dividends per common share declared		$0.2725	-	$0.2725

For the six months ended June 30, 2010 millions of Canadian dollars (except per share amounts) (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Operating revenues				
Electric	T	$739.7	$(739.7)	-
Finance income from direct finance lease	T	29.0	(29.0)	-
Other	T	18.8	(18.8)	-
Regulated	F, T, U	-	721.0	$721.0
Non-regulated	A, T, U	-	82.2	82.2
Total operating revenues		787.5	15.7	803.2
Operating expenses				
Regulated fuel for generation and purchased power	U, V	375.0	(45.4)	329.6
Regulated fuel adjustment		(52.0)	-	(52.0)
Non-regulated fuel for generation and purchase power	A, V	-	43.9	43.9
Non-regulated direct costs	U	-	23.5	23.5
Operating, maintenance and general	A, K, R, U, W	158.0	2.3	160.3
Provincial, state and municipal taxes	A	24.5	(0.8)	23.7
Depreciation and amortization	A, C, X	85.4	10.2	95.6
Regulatory amortization	X	10.9	(10.9)	-
Total operating expenses		601.8	22.8	624.6
Income from operations		185.7	(7.1)	178.6
Income from equity investments	A, C	6.2	1.7	7.9
Other income (expenses), net	F, J, S, T, U, W, Y	-	17.7	17.7
Financing charges	P, W, Y	84.3	(84.3)	-
Interest expense, net	A, C, P, U, W, Y	-	75.4	75.4
Income before provision for income taxes		107.6	21.2	128.8
Income tax expense (recovery)	A, C	0.9	(2.4)	(1.5)
Net income		106.7	23.6	130.3
Non-controlling interest in subsidiaries	P	-	4.0	4.0
Net income attributable to common shares		$106.7	$19.6	$126.3
Weighted average number of shares (in millions)				
Basic		113.3	0.4	113.7
Diluted		120.2	(0.1)	120.1
Earnings per common share				
Basic		$0.94	$0.17	$1.11
Diluted		$0.92	$0.16	$1.08
Dividends per common share declared		$0.5550	-	$0.5550

For the nine months ended September 30, 2010 millions of Canadian dollars (except per share amounts) (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Operating revenues				
Electric	T	$1,074.0	$(1,074.0)	-
Finance income from direct finance lease	T	42.8	(42.8)	-
Other	T	44.2	(44.2)	-
Regulated	F, T, U	-	1,053.9	$1,053.9
Non-regulated	A, T, U	-	143.3	143.3
Total operating revenues		1,161.0	36.2	1,197.2
Operating expenses				
Regulated fuel for generation and purchased power	U, V	541.9	(65.1)	476.8
Regulated fuel adjustment		(75.0)	-	(75.0)
Non-regulated fuel for generation and purchase power	A, V	-	64.5	64.5
Non-regulated direct costs	U	-	46.1	46.1
Operating, maintenance and general	A, K, R, U, W	244.1	3.4	247.5
Provincial, state and municipal taxes	A	36.8	(1.3)	35.5
Depreciation and amortization	A, C, X	127.9	15.8	143.7
Regulatory amortization	X	16.7	(16.7)	-
Total operating expenses		892.4	46.7	939.1
Income from operations		268.6	(10.5)	258.1
Income from equity investments	A, C	11.3	2.3	13.6
Other income (expenses), net	F, J, S, T, U, W, Y	-	18.0	18.0
Financing charges	P, W, Y	124.6	(124.6)	-
Interest expense, net	A, C, P, U, W, Y	-	111.5	111.5
Income before provision for income taxes		155.3	22.9	178.2
Income tax expense (recovery)	A, C	0.6	1.9	2.5
Net income		154.7	21.0	175.7
Non-controlling interest in subsidiaries	P	0.1	6.0	6.1
Net income of Emera Incorporated		154.6	15.0	169.6
Preferred stock dividends	C	3.1	(0.1)	3.0
Net income attributable to common shareholders		$151.5	$15.1	$166.6
Weighted average number of shares (in millions)				
Basic		113.5	0.5	114.0
Diluted		120.2	0.1	120.3
Earnings per common share				
Basic		$1.33	$0.13	$1.46
Diluted		$1.31	$0.12	$1.43
Dividends per common share declared		$1.1625	-	$1.1625

For the year ended December 31, 2010 millions of Canadian dollars (except per share amounts)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Operating revenues				
Electric	T	$1,436.1	$(1,436.1)	-
Finance income from direct finance lease	T	56.5	(56.5)	-
Other	T	61.1	(61.1)	-
Regulated	F, T, U	-	1,411.6	$1,411.6
Non-regulated	A, T, U	-	194.5	194.5
Total operating revenues		1,553.7	52.4	1,606.1
Operating expenses				
Regulated fuel for generation and purchased power	U, V	718.7	(84.1)	634.6
Regulated fuel adjustment		(99.0)	-	(99.0)
Non-regulated fuel for generation and purchase power	A, V	-	83.9	83.9
Non-regulated direct costs	U	-	62.3	62.3
Operating, maintenance and general	A, J, K, R, U, W	336.1	15.1	351.2
Provincial, state and municipal taxes	A	49.1	(1.7)	47.4
Depreciation and amortization	A, C, X	173.6	39.9	213.5
Regulatory amortization	X	41.3	(41.3)	-
Total operating expenses		1,219.8	74.1	1,293.9
Income from operations		333.9	(21.7)	312.2
Income from equity investments	A, C	13.6	1.7	15.3
Other income (expenses), net	F, J, S, T, U, W, Y	-	12.5	12.5
Financing charges	P, W, Y	168.4	(168.4)	-
Interest expense, net	A, C, P, U, W, Y	-	148.8	148.8
Income before provision for income taxes		179.1	12.1	191.2
Income tax expense (recovery)	A, C	(12.8)	4.7	(8.1)
Net income		191.9	7.4	199.3
Non-controlling interest in subsidiaries	P	(2.3)	7.9	5.6
Net income of Emera Incorporated		194.2	(0.5)	193.7
Preferred stock dividends	C	3.1	(0.1)	3.0
Net income attributable to common shareholders		$191.1	$(0.4)	$190.7
Weighted average number of shares (in millions)				
Basic		113.7	0.5	114.2
Diluted		120.3	0.1	120.4
Earnings per common share				
Basic		$1.68	$(0.1)	$1.67
Diluted		$1.65	-	$1.65
Dividends per common share declared		$1.1625	-	$1.1625

The consolidated statements of cash flows for the 2010 periods reconciled from CGAAP to USGAAP are as follows:

For the three months ended March 31, 2010 millions of Canadian dollars (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Net cash used in operating activities	A, P, R, Y	$(5.7)	$3.1	$(2.6)
Net cash used in investing activities	A, Y	(66.7)	(1.6)	(68.3)
Net cash provided by financing activities	P, R	62.3	(2.1)	60.2
Effect of exchange rate changes on cash and cash equivalents		(0.2)	0.6	0.4
Net decrease in cash and cash equivalents		(10.3)	-	(10.3)
Cash and cash equivalents, beginning of period	A	21.8	(1.6)	20.2
Cash and cash equivalents, end of period	A	$11.5	$(1.6)	$9.9

For the six months ended June 30, 2010 millions of Canadian dollars (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Net cash provided by operating activities	A, P, R, Y	$105.1	$4.9	$110.0
Net cash used in investing activities	A, Y	(298.2)	(3.9)	(302.1)
Net cash provided by financing activities	A, P, R	220.0	(3.2)	216.8
Effect of exchange rate changes on cash and cash equivalents		0.5	(0.3)	0.2
Net increase (decrease) in cash and cash equivalents		27.4	(2.5)	24.9
Cash and cash equivalents, beginning of period	A	21.8	(1.6)	20.2
Cash and cash equivalents, end of period	A	$49.2	$(4.1)	$45.1

For the nine months ended September 30, 2010 millions of Canadian dollars (Unaudited)	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Net cash provided by operating activities	A, P, R, Y	$230.9	$7.1	$238.0
Net cash used in investing activities	A, Y	(452.0)	(6.4)	(458.4)
Net cash provided by financing activities	A, P, R	247.2	(3.7)	243.5
Effect of exchange rate changes on cash and cash equivalents		(0.4)	0.6	0.2
Net increase (decrease) in cash and cash equivalents		25.7	(2.4)	23.3
Cash and cash equivalents, beginning of period	A	21.8	(1.6)	20.2
Cash and cash equivalents, end of period	A	$47.5	$(4.0)	$43.5

For the year ended December 31, 2010 millions of Canadian dollars	Notes	CGAAP	Effect of transition to USGAAP	USGAAP
Net cash provided by operating activities	A, C, P, R, Y, J	$416.4	$2.8	$419.2
Net cash used in investing activities	A, C, Y, J	(894.8)	8.8	(886.0)
Net cash provided by financing activities	A, P, R	466.2	(11.6)	454.6
Effect of exchange rate changes on cash and cash equivalents		(0.2)	(0.5)	(0.7)
Net decrease in cash and cash equivalents		(12.4)	(0.5)	(12.9)
Cash and cash equivalents, beginning of period	A	21.8	(1.6)	20.2
Cash and cash equivalents, end of period	A	$9.4	$(2.1)	$7.3

NOTES TO THE TRANSITIONAL ADJUSTMENTS

Under USGAAP, the Company is (i) measuring certain assets, liabilities, revenues and expenses differently than it had been under CGAAP (see details on each measurement change below); and (ii) disclosing certain assets, liabilities, revenues and expenses on different lines in the financial statements than they had been under CGAAP (see details on each classification change below).

A. Accounting for joint ventures (measurement difference)

The Company exercises joint control over its investment in Bear Swamp with its third-party partner and therefore, proportionately consolidated the investment under CGAAP. Under the proportionate consolidation method the Company recognized its pro-rata share of the jointly controlled assets and liabilities of Bear Swamp in the Company's balance sheet and recognized its pro-rata share of the revenues and expenses of Bear Swamp in the Company's income statement.

Under USGAAP, the Company accounts for its investment in Bear Swamp using the equity method, whereby the amount of the investment is adjusted quarterly for the Company's pro-rata share of Bear Swamp's post-acquisition net income and reduced by the amount of any dividends received. The Company's pro-rata share of Bear Swamp's net income is recognized in "Income from equity investments".

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Current assets		
Cash and cash equivalents	$(1.6)	$(2.1)
Restricted cash	(1.0)	(1.0)
Receivables, net	(3.9)	(3.2)
Derivative instruments	-	(0.8)
Prepaid expenses	(0.2)	(0.2)
Property, plant and equipment	(51.0)	(48.1)
Other assets		
Derivative instruments	(16.1)	(5.3)
Investments subject to significant influence	(2.0)	(14.3)
Other	(0.6)	(0.4)
Current liabilities		
Current portion of long-term debt	(1.6)	(2.1)
Accounts payable	(1.2)	(1.9)
Derivative instruments	(1.4)	(2.9)
Other current liabilities	-	(0.1)
Long-term liabilities		
Long-term debt	(63.8)	(58.5)
Derivative instruments	(5.9)	(10.4)
Other long-term liabilities	(2.6)	-
Equity		
Accumulated other comprehensive income (loss)	0.1	0.5

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31, 2010 (Unaudited)	6 months ended June 30, 2010 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Non-regulated operating revenues	$(3.6)	$(15.6)	$(23.0)	$(28.1)
Non-regulated fuel for generation and purchased power	(4.6)	(9.0)	(13.0)	(17.2)
Operating, maintenance and general	(0.9)	(1.7)	(2.9)	(4.9)
Provincial, state and municipal taxes	(0.4)	(0.8)	(1.3)	(1.7)
Depreciation and amortization	(0.4)	(0.8)	(1.2)	(1.8)
Income from equity investments	(1.6)	1.8	2.4	1.8
Other income (expenses), net	(0.2)	-	-	-
Interest expense, net	(0.3)	(0.5)	(0.7)	(1.0)
Income tax expense (recovery)	1.2	(1.0)	(1.5)	0.3

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the effect on the Statements of Cash Flows is as follows:

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Net cash provided by (used in) operating activities	$0.1	$(3.2)	$(4.5)	$(0.4)
Net cash (used in) provided by investing activities	(0.1)	(0.2)	0.1	1.5
Net cash provided by (used in) financing activities	-	0.9	1.5	(1.6)
Cash and cash equivalents, beginning of period	(1.6)	(1.6)	(1.6)	(1.6)
Cash and cash equivalents, end of period	(1.6)	(4.1)	(4.5)	(2.1)

B. Offsetting (measurement difference)

Certain items on the balance sheets are being offset where a legal right of setoff exists. Differences exist between CGAAP and USGAAP in defining what balances may be offset. As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Receivables, net	$(0.9)	-
Accounts payable	(0.9)	-

C. Income taxes (measurement difference)

In addition to the tax effects of other transition adjustments, the following are included in the income tax adjustments.

Investment tax credits (“ITCs”)

Under CGAAP, the Company recognizes ITCs as a reduction from the related expenditures where there is reasonable assurance of collection. Under USGAAP, the Company recognizes ITCs as a reduction of income tax expense in the current and future periods to the extent that realization of such benefit is more likely than not.

Tax rates

Under CGAAP, the Company measured income taxes using substantively enacted income tax rates. Under USGAAP, the Company uses enacted income tax rates. The Company recognized an income tax liability under USGAAP for the difference between the enacted tax rates and the substantively enacted tax rates for the Part VI.1 tax deduction related to preferred share dividends.

Uncertain tax positions

Under CGAAP, the Company recognized the benefit of an uncertain tax position when it was probable of being sustained.

Under USGAAP, the Company recognizes the benefit of an uncertain tax position only when it is more likely than not that such a position will be sustained by the taxing authorities based on the technical merits of the position. The current and deferred income tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Current assets		
Income taxes receivable	-	$(6.4)
Deferred income taxes	$(23.6)	(14.5)
Property, plant and equipment	1.1	1.4
Other assets		
Deferred income taxes	61.7	17.9
Regulatory assets	(23.1)	(134.9)
Investments subject to significant influence	-	(0.6)
Other	1.1	0.7
Current liabilities		
Income taxes payable	1.2	(0.8)
Deferred income taxes	-	8.5
Regulatory liabilities	6.7	4.1
Other current liabilities	1.3	1.1
Long-term liabilities		
Deferred income taxes	(53.6)	(176.5)
Regulatory liabilities	61.4	32.4
Equity		
Accumulated other comprehensive income (loss)	0.2	0.2
Retained earnings	-	(5.4)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010 (Unaudited)
Depreciation and amortization	$0.1	$0.2	$0.3	$0.4
Income from equity investments	-	(0.1)	(0.4)	(0.6)
Interest expense, net	(0.3)	(0.3)	(0.4)	(0.2)
Income tax expense (recovery)	(1.0)	(1.0)	3.7	4.3
Preferred stock dividends	-	-	(0.1)	(0.1)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the effect on the Statements of Cash Flows is as follows:

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Net cash provided by operating activities	-	-	-	$0.3
Net cash used in investing activities	-	-	-	(0.3)

D. Derivatives (classification change)

Under CGAAP, the Company was disclosing its derivatives in valid hedging relationships and held-for-trading derivatives as separate line items on the balance sheet. Under USGAAP, the Company has included these balances together in “Derivative instruments”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Current assets		
Derivative instruments	$39.4	$50.5
Derivatives in a valid hedging relationship	(26.3)	(28.4)
Held-for-trading derivatives	(13.1)	(22.1)
Other assets		
Derivative instruments	61.6	41.4
Derivatives in a valid hedging relationship	(30.9)	(26.1)
Held-for-trading derivatives	(30.7)	(15.3)
Current liabilities		
Derivative instruments	79.6	39.7
Derivatives in a valid hedging relationship	(61.0)	(8.6)
Held-for-trading derivatives	(18.6)	(31.1)
Long-term liabilities		
Derivative instruments	41.5	39.3
Derivatives in a valid hedging relationship	(25.7)	(21.3)
Held-for-trading derivatives	(15.8)	(18.0)

E. Regulatory assets and liabilities (classification change)

Under CGAAP, the Company was disclosing its regulatory assets and liabilities in other assets and liabilities respectively. Under USGAAP, the Company discloses its regulatory assets and liabilities as separate line items on the balance sheet.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Current assets		
Regulatory assets	$55.8	$63.7
Other assets		
Regulatory assets	273.1	466.3
Other	(328.9)	(530.0)
Current liabilities		
Regulatory liabilities	21.2	22.1
Long-term liabilities		
Regulatory liabilities	0.5	11.9
Other long-term liabilities	(21.7)	(34.0)

F. Hedging (measurement change)

Brunswick Pipeline

Under CGAAP, cash flow hedging strategies of Brunswick Pipeline qualified for hedge accounting. Under USGAAP, the Company determined that certain cash flow hedging strategies did not qualify for hedge accounting primarily due to differences in effectiveness testing requirements. The Company changed its effectiveness testing for hedges put in place beginning January 1, 2010 and these hedges qualify for hedge accounting under USGAAP.

As a result of disqualifying cash flow hedges in place prior to 2010, Brunswick Pipeline must recognize changes in fair value on these derivatives in net income of the period, rather than deferring the changes to accumulated other comprehensive income. In addition, because of the change in effectiveness testing effective January 1, 2010, Brunswick Pipeline must measure and recognize any ineffectiveness of its hedging strategies in net income of the period.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Net investment in direct financing lease	$3.2	$3.2
Accumulated other comprehensive income (loss)	(7.4)	(1.4)
Retained earnings	10.6	4.6

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Regulated operating revenues	$(2.0)	$(4.2)	$(5.9)	$(7.4)
Other income (expenses), net	1.3	(0.7)	0.5	1.4

Nova Scotia Power

In addition to the above, effective for 2011, NSPI implemented an amended hedge accounting policy which was approved by the UARB. The amended policy resulted from stakeholder requests to simplify the accounting for derivatives used to manage risk and to alleviate any USGAAP issues which would result in increased income volatility. The amended policy is applied retrospectively with restatement of prior periods with the exception of prior period income, and requires regulatory deferral for commodity, foreign exchange and interest derivatives documented as economic hedges and for physical contracts that do not qualify for the NPNS exception under USGAAP.

As a result of the amended accounting policy, NSPI receives regulatory deferral for any changes in fair value on derivatives documented as economic hedges. As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Current assets		
Regulatory assets	$75.9	$26.9
Other assets		
Regulatory assets	20.0	12.2
Current liabilities		
Regulatory liabilities	22.1	28.6
Long-term liabilities		
Regulatory liabilities	29.8	21.2
Equity		
Accumulated other comprehensive income (loss)	44.0	(10.7)

G. Issue costs

Classification change

Under CGAAP, debt financing costs, premiums and discounts were netted against long-term debt. Under USGAAP, debt financing costs are included in “Other” as part of “Other assets”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other current assets	$1.8	$1.0
Other, included in other assets	13.5	16.8
Short-term debt	-	0.4
Long-term debt	15.3	17.4

Measurement Change

Under CGAAP, the straight-line method of amortizing debt financing costs, premiums and discounts was used to approximate the effective interest method. Under USGAAP, the straight-line method is not appropriate so the effective interest method has been adopted.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other, included in other assets	$1.1	$1.1
Long-term debt	2.2	2.2
Retained earnings	(1.1)	(1.1)

H. Current other assets and liabilities (classification change)

Under CGAAP, the Company was disclosing its other assets and liabilities on the balance sheet as long-term. Under USGAAP, the Company has included the current portion of these balances in “Other current assets” and “Other current liabilities”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other current assets	$1.5	$2.1
Other, included in other assets	(1.5)	(2.1)
Other current liabilities	2.8	3.9
Other long-term liabilities	(2.8)	(3.9)

I. Construction work-in-progress (classification change)

Under CGAAP, the Company was disclosing its construction work-in-progress (“CWIP”) as a separate line item on the balance sheet. Under USGAAP, the Company has included this balance in “Property, plant and equipment” and will disclose its CWIP balance annually in the notes to the December 31 financial statements.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Property, plant and equipment	$220.2	$333.0
Construction work-in-progress	(220.2)	(333.0)

J. Business combinations (measurement change)

Acquisition-related transaction costs

Under CGAAP, acquisition-related transaction costs were capitalized and included in the allocation of the purchase price to the acquired assets and liabilities. Under USGAAP, acquisition-related transaction costs are expensed in the period incurred, beginning with transactions completed on or after January 1, 2009.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Property, plant and equipment	$(0.2)	$(0.2)
Other, included in other assets	-	(0.5)
Goodwill	-	(10.7)
Accumulated other comprehensive income (loss)	-	0.1
Retained earnings	(0.2)	(11.5)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Operating, maintenance and general	-	-	-	$11.3

Business combinations achieved in stages

Under CGAAP, for business combinations achieved in stages, the acquirer does not re-measure its previously held equity interest in an acquired company. Under USGAAP, the acquirer re-measures the previously held equity interest at the acquisition-date fair value and recognizes the resulting gain or loss, if any, in income.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Property, plant and equipment	$0.4	-
Regulatory assets	(0.4)	-
Goodwill	-	$(2.4)
Retained earnings	-	(2.4)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Other income (expenses), net	-	-	-	$(2.4)

Negative goodwill

Under CGAAP, where the net assets in a business combination exceed the purchase price, sometimes referred to as “negative goodwill”, the excess should be eliminated, to the extent possible, by allocating the negative goodwill as a pro rata reduction of the amounts that otherwise would be assigned to certain of the acquired assets. Under USGAAP, the negative goodwill gives rise to an extraordinary gain which is recognized in income.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Investments subject to significant influence	-	$21.5
Accumulated other comprehensive income (loss)	-	(0.6)
Retained earnings	-	22.1

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Other income (expenses), net	-	$22.5	$22.3	$22.1

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the effect on the Statements of Cash Flows is as follows:

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Net cash used in operating activities	-	-	-	(11.3)
Net cash provided by investing activities	-	-	-	11.3

K. Pension and other post-retirement benefits (measurement change)

Under CGAAP, the Company disclosed, but did not recognize, its unamortized gains and losses, its past service costs, and its unamortized transitional obligation associated with pension and other post-retirement benefits. Under USGAAP, the Company has recognized its unfunded pension obligation as a liability; the unamortized gains and losses and past service costs are recognized in AOCL; and the unamortized transitional obligation previously determined under CGAAP is recognized in “Retained earnings”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other assets		
Regulatory assets	$9.2	$11.6
Other	(94.3)	(113.5)
Goodwill	-	1.5
Current liabilities		
Pension and post-retirement liabilities	9.2	8.9
Long-term liabilities		
Deferred income taxes	(14.3)	(14.7)
Pension and post-retirement liabilities	292.4	400.0
Other long-term liabilities	(88.0)	(102.4)
Equity		
Accumulated other comprehensive income (loss)	(277.6)	(387.9)
Retained earnings	(6.8)	(4.3)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Operating, maintenance and general	$(0.6)	$(1.1)	$(1.7)	$(2.3)

L. Intangibles (classification change)

Under CGAAP, the Company was disclosing its intangibles as a separate line item on the balance sheet. Under USGAAP, the Company has included this balance in “Other” as part of “Other assets”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other, included in other assets	$92.1	$98.2
Intangibles	(92.1)	(98.2)

M. Investments (measurement change)

Under CGAAP, certain investments of the Company were classified as an available-for-sale investment and measured at cost as the investments are not actively traded in an open market. Under USGAAP, investments measured at cost because they do not trade in an active market are not included in “Available-for-sale investment” therefore the Company has included these investments in “Other assets”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other, included in other assets	$46.3	46.2
Available-for-sale investment	(46.3)	(46.2)

N. Accounts payable (classification change)

Under CGAAP, trade and non-trade payables were recognized in accounts payable and accrued charges. Under USGAAP, trade payables are recognized in “Accounts payable” and non-trade payables are recognized in “Other current liabilities”.

As at January 1 and December 31, 2010, the effect the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Accounts payable	$220.4	$296.5
Accounts payable and accrued charges	(305.9)	(399.6)
Other current liabilities	85.5	103.1

O. Dividends payable (classification change)

Under CGAAP, the Company was disclosing dividends payable as a separate line item on the balance sheet. Under USGAAP, the Company has included this balance in “Other current liabilities”.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Dividends payable	$(1.7)	$(1.8)
Other current liabilities	1.7	1.8

P. Preferred stock of Nova Scotia Power Inc. (measurement change)

Under CGAAP, NSPI’s preferred stock was classified as a liability; preferred stock dividends were classified as an expense in the income statement and were accrued monthly; and issuance costs were deferred on the balance sheet as a deferred financing charge and amortized to income over the life of the preferred stock.

Under USGAAP, NSPI’s preferred stock is classified as equity in “Non-controlling interest” as the preferred stock does not meet the USGAAP definition of a liability; preferred stock dividends are deducted from retained earnings and are accrued as declared; and issuance costs are netted against the preferred stock on the balance sheet and are not amortized.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Other current liabilities	$0.3	$0.3
Long-term debt	0.7	0.6
Preferred shares issued by a subsidiary	(135.0)	(135.0)
Retained earnings	1.8	1.9
Non-controlling interest in subsidiaries	132.2	132.2

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Financing charges	$(2.0)	$(4.0)	$(6.0)	$(8.0)
Interest expense, net	-	(0.1)	(0.1)	(0.1)
Non-controlling interest in subsidiaries	2.0	4.0	6.0	8.0

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the effect on the Statements of Cash Flows is as follows:

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Net cash provided by operating activities	$2.0	$4.0	$6.0	$8.0
Net cash used in financing activities	(2.0)	(4.0)	(6.0)	(8.0)

Q. Non-controlling interest in subsidiaries (classification change)

Under CGAAP, non-controlling interest in subsidiaries (“NCI”) is classified outside shareholders’ equity, after liabilities. Under USGAAP, NCI is included in total equity.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Non-controlling interest	$(32.1)	$(20.7)
Accumulated other comprehensive income (loss)	-	(1.5)
Non-controlling interest in subsidiaries	32.1	22.2

R. Stock-based compensation (measurement change)

Employee Common Share Purchase Plan

Under CGAAP, the Company was recognizing the amount of its contribution in excess of 5 percent of the average market price of the shares. Under USGAAP, the Company’s employee common share purchase plan is considered compensatory and the Company’s contribution to the plan should be recognized.

Senior Management Stock Option Plan

Under CGAAP, the Company was amortizing the compensation cost associated with its stock option over two years, the average vesting period of the four awards. Under USGAAP, the Company has chosen to amortize the compensation cost over four years, the vesting period of the entire award.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Common stock	$1.2	$1.3
Contributed surplus	(0.6)	(0.5)
Retained earnings	(0.6)	(0.8)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is as reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Operating, maintenance and general	$0.1	$0.1	$0.2	$0.2

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the effect on the Statements of Cash Flows results is as follows:

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Net cash used in operating activities	$(0.1)	$(0.1)	$(0.2)	$(0.2)
Net cash provided by financing activities	0.1	0.1	0.2	0.2

S. Foreign currency translation (measurement change)

Under CGAAP, the Company's Canadian division of Emera Energy Services had a Canadian functional currency. Monetary assets and liabilities denominated in a foreign currency were converted to Canadian dollars at rates of exchange prevailing at the balance sheet date. The effect of periodic changes in exchange rates were charged to income.

Under USGAAP, the Company has determined that Emera Energy Services has a US functional currency. Asset and liabilities are translated using the exchange rates in effect at the balance sheet date and the results of operations at the average rates for the periods. The resulting exchange gains (losses) on the assets and liabilities are deferred and included in accumulated other comprehensive income.

As at January 1 and December 31, 2010, the effect on the Balance Sheets is reflected in the following increases (decreases):

As at millions of Canadian dollars	January 1 2010	December 31 2010
Accumulated other comprehensive income	$1.2	$1.6
Retained earnings	(1.2)	(1.6)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Other income (expenses), net	$(0.4)	$(0.4)	$(0.1)	$(0.3)

T. Revenue (classification change)

Under CGAAP, revenue was recognized in electric revenue, finance income from direct finance lease and other revenue. Under USGAAP, revenue is recognized in regulated operating revenues, non-regulated operating revenue income and other income (expense), net.

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 20 2010 (Unaudited)	Year ended December 31 2010
Electric revenue	$(412.1)	$(739.7)	$(1,074.0)	$(1,436.1)
Finance income from direct finance lease	(14.2)	(29.0)	(42.8)	(56.5)
Other revenue	(3.8)	(18.8)	(44.2)	(61.1)
Regulated operating revenues	391.2	712.8	1,040.1	1,391.9
Non-regulated operating revenues	38.6	74.2	119.9	159.9
Other income (expense), net	0.3	0.5	1.0	1.9

U. Netting of certain revenues and expenses (measurement change)

Under CGAAP, the Company was netting certain revenues and expenses in its statements of income. Under USGAAP, revenues are classified on a gross or net basis depending on whether the Company is acting as the principal or an agent in the transaction. The adoption of USGAAP has resulted in certain revenue transactions disclosed on a net basis under CGAAP to be presented on a gross basis under USGAAP.

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Regulated operating revenues	$6.2	$12.5	$19.8	$27.2
Non-regulated operating revenues	8.1	23.5	46.4	62.6
Regulated fuel for generation and purchased power	3.9	7.6	12.5	17.0
Non-regulated direct costs	8.2	23.5	46.1	62.3
Operating, maintenance and general	2.2	4.9	7.6	10.5
Other income (expenses), net	0.1	0.2	0.2	0.3
Interest expense, net	0.1	0.2	0.2	0.3

V. Fuel for generation and purchased power (classification change)

Under CGAAP, all fuel for generation and purchased power was recognized as such. Under USGAAP, regulated and non-regulated fuel for generation and purchased power are recognized separately.

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Regulated fuel for generation and purchased power	$(27.7)	$(52.9)	$(77.5)	$(101.1)
Non-regulated fuel for generation and purchased power	27.7	52.9	77.5	101.1

W. Interest expense (classification change)

Under CGAAP, interest expense, amortization of defeasance costs, and foreign exchange gains and losses were included in financing charges. Under USGAAP, interest expense is disclosed in a separate line item and amortization of defeasance costs and foreign exchange gains and losses are included in "Other income (expense), net".

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Operating, maintenance and general	-	$0.1	$0.1	$0.2
Other income (expenses), net	$(5.6)	(9.9)	(16.6)	(26.0)
Financing charges	(45.8)	(90.0)	(136.8)	(186.5)
Interest expense, net	40.2	80.0	120.1	160.3

X. Regulatory amortization (classification change)

Under CGAAP, regulatory amortization was disclosed as a separate line item. Under USGAAP, regulatory amortization is included in "Depreciation and amortization".

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Depreciation and amortization	$5.4	$10.9	$16.7	$41.3
Regulatory amortization	(5.4)	(10.9)	(16.7)	(41.3)

Y. Allowance for funds used during construction (classification change)

Under CGAAP, AFUDC was included in financing charges. Under USGAAP, allowance for equity funds used during construction is included in "Other income (expenses), net" and allowance for borrowed funds used during construction is netted against "Interest expense, net".

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the pre-tax effect on the Statements of Income is reflected in the following increases (decreases):

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Other income (expenses), net	$2.6	$5.7	$10.6	$15.6
Financing charges	4.6	9.7	18.2	26.0
Interest expense, net	(2.0)	(4.0)	(7.6)	(10.4)

For the quarters ended March 31, June 30, September 30 and year ended December 31, 2010, the effect on the Statements of Cash Flows is as follows:

For the millions of Canadian dollars	3 months ended March 31 2010 (Unaudited)	6 months ended June 30 2010 (Unaudited)	9 months ended September 30 2010 (Unaudited)	Year ended December 31 2010
Net cash provided by operating activities	$2.0	$4.0	$7.6	$10.4
Net cash provided by investing activities	(2.0)	(4.0)	(7.6)	(10.4)

36. SUBSEQUENT EVENTS

Bangor Hydro

On January 31, 2012, Bangor Hydro completed the issue of an unsecured $70.0 million USD senior note. The Series 2012-A Senior Note bears interest at a rate of 3.61 percent per annum until January 31, 2022. The net proceeds of the note offering were used to repay borrowings under the revolving credit facility.

GBPC

On January 25, 2012, GBPC entered into an unsecured credit agreement with Scotiabank (Bahamas) Limited in the amount of $56.2 million USD. The proceeds of the credit agreement will be used to finance the construction of a 52-MW power plant on Grand Bahama Island. The credit agreement bears interest at a rate of the three month LIBOR rate plus 1.2 percent and is repayable in forty equal, consecutive quarterly installments over a ten year period. The payments commence at the earlier of six months after the completion of the construction of the power plant or January 31, 2013.

Financial Statements

Nova Scotia Power Inc.
Statements of Income (Regulated)

For the millions of Canadian dollars			Three months ended December 31				Twelve months ended December 31	
	Actual 2011	[redacted]	*Test Year 2009*	*Prior Year 2010 (as adjusted)*	***Actual 2011***	[redacted]	*Test Year 2009*	*Prior Year 2010 (as adjusted)*
Operating revenues	**$289.2**		$322.8	$303.2	**$1,233.0**		$1,257.0	$1,191.2
Operating expenses								
Fuel for generation and purchased power	**127.0**		144.0	146.9	**546.5**		545.0	578.9
Fuel for generation and purchased power - affiliates	**0.8**		-	0.1	**1.1**		-	8.1
Fuel adjustment	**(5.9)**		-	(26.3)	**(12.5)**		-	(102.7)
Operating, maintenance and general	**73.8**		54.9	65.6	**262.6**		218.2	237.8
Provincial grants and taxes	**9.8**		10.0	10.1	**38.7**		40.1	40.1
Depreciation and amortization	**58.7**		41.6	69.2	**186.9**		163.3	193.3
Total operating expenses	**264.2**		250.5	265.6	**1,023.3**		966.6	955.5
Income from operations	**25.0**		72.3	37.6	**209.7**		290.4	235.7
Other expenses, net	**2.1**		1.9	3.5	**8.9**		8.4	11.3
Interest expense, net	**23.5**		26.4	26.8	**104.0**		104.0	104.6
(Loss) income before provision for income taxes	**(0.6)**		44.0	7.3	**96.8**		178.0	119.8
Income tax (recovery) expense	**(27.2)**		15.2	(11.0)	**(42.4)**		64.7	(7.3)
Net income of Nova Scotia Power Inc.	**26.6**		28.8	18.3	**139.2**		113.3	127.1
Preferred stock dividends	**1.9**		3.4	1.9	**7.9**		13.8	7.9
Net income	**24.7**		25.4	16.4	**131.3**		99.5	119.2
2009 ROE settlement (AAA-2)	**-**		-	5.5	**-**		-	5.5
Net income attributable to common shareholders	**$24.7**		$25.4	$21.9	**$131.3**		$99.5	$124.7

Notes:

1. Fuel for generation and purchased power - affiliates are not separately budgeted.
2. Reclassifications have been made to the Test Year 2009 numbers in order to report amounts using the same line items used for US GAAP reporting purposes. The amounts used for the Test Year 2009 numbers are compliant with Canadian GAAP only.

Balance Sheets (Regulated)

As at millions of Canadian dollars	**December 31 2011**	*December 31 2010 (as adjusted)*
Assets		
Current assets		
Cash	**-**	$0.3
Receivables, net	**$208.6**	192.5
Due from related parties	**91.7**	76.0
Income taxes receivable	**40.0**	34.3
Inventory	**155.8**	154.2
Derivative instruments	**15.9**	31.0
Regulatory assets	**124.7**	71.8
Prepaid expenses	**6.4**	6.0
Other current assets	**-**	1.8
Total current assets	**643.1**	567.9
Property, plant and equipment, net of accumulated depreciation	**3,033.6**	2,935.2
Other assets		
Deferred income taxes	**-**	15.1
Derivative instruments	**28.6**	28.9
Regulatory assets	**173.0**	232.5
Intangibles, net of accumulated amortization	**73.6**	73.2
Other	**12.8**	11.9
Total other assets	**288.0**	361.6
Total assets	**$3,964.7**	$3,864.7

	December 31 2011	*December 31 2010 (as adjusted)*
Liabilities and Equity		
Current liabilities		
Short-term debt	**$63.9**	$48.3
Current portion of long-term debt	**-**	0.1
Accounts payable	**144.2**	157.9
Due to related parties	**1.3**	6.2
Deferred income taxes	**10.8**	5.8
Derivative instruments	**33.3**	23.0
Regulatory liabilities	**23.2**	52.4
Pension and post-retirement liabilities	**8.3**	8.2
Other current liabilities	**77.3**	67.2
Total current liabilities	**362.3**	369.1
Long-term liabilities		
Long-term debt	**1,961.0**	1,949.1
Deferred income taxes	**23.6**	-
Derivative instruments	**13.0**	11.2
Regulatory liabilities	**29.3**	61.7
Asset retirement obligations	**91.1**	138.7
Pension and post-retirement liabilities	**420.0**	314.7
Other long-term liabilities	**4.5**	5.6
Total long-term liabilties	**2,542.5**	2,481.0
Redeemable preferred stock	**132.2**	132.2
Equity		
Common stock	**1,034.7**	984.7
Accumulated other comprehensive loss	**(476.7)**	(365.7)
Retained earnings	**369.7**	263.4
Total equity	**927.7**	882.4
Total liabilities and equity	**$3,964.7**	$3,864.7

Operating Revenues (Regulated)

For the			Three months ended				Twelve months ended	
millions of Canadian dollars			December 31				December 31	
	Actual 2011	[redacted]	*Test Year 2009*	*Prior Year 2010 (as adjusted)*	***Actual 2011***	[redacted]	*Test Year 2009*	*Prior Year 2010 (as adjusted)*
Electric Revenues:		[redacted]				[redacted]		
Residential	**$141.0**	[redacted]	$141.9	$137.1	**$564.9**	[redacted]	$542.8	$531.0
Commercial		[redacted]				[redacted]		
Small General	**7.7**	[redacted]	8.8	7.7	**32.3**	[redacted]	33.6	30.3
General	**68.8**	[redacted]	70.3	65.6	**271.3**	[redacted]	276.6	258.8
Large General	**9.3**	[redacted]	9.3	8.8	**38.2**	[redacted]	38.0	36.2
Total Commercial	**85.8**	[redacted]	88.4	82.1	**341.8**	[redacted]	348.2	325.3
Industrial		[redacted]				[redacted]		
Small Industrial	**6.4**	[redacted]	6.6	6.2	**26.8**	[redacted]	26.1	25.7
Medium Industrial	**11.9**	[redacted]	13.6	11.4	**46.4**	[redacted]	53.2	44.0
Large Industrial	**17.0**	[redacted]	17.7	17.1	**70.6**	[redacted]	71.1	68.0
Extra Large Industrial 2P-RTP	**4.0**	[redacted]	32.9	26.4	**93.1**	[redacted]	130.3	111.3
GRLF	**0.7**	[redacted]	0.4	0.1	**1.0**	[redacted]	1.1	1.2
Mersey	**5.1**	[redacted]	5.3	4.8	**22.1**	[redacted]	21.1	19.1
Total Industrial	**45.1**	[redacted]	76.5	66.0	**260.0**	[redacted]	302.9	269.3
Other		[redacted]				[redacted]		
Municipal	**4.6**	[redacted]	4.5	4.4	**17.7**	[redacted]	17.6	16.8
Unmetered	**6.2**	[redacted]	6.8	6.5	**24.8**	[redacted]	25.2	24.3
Total Other	**10.8**	[redacted]	11.3	10.9	**42.5**	[redacted]	42.8	41.1
Total In-Province Electric Revenues	**$282.7**	[redacted]	$318.1	$296.1	**$1,209.2**	[redacted]	$1,236.7	$1,166.7
Export Revenues	**0.2**	[redacted]	0.6	0.3	**0.5**	[redacted]	4.6	0.6
Total Electric Revenues	**$282.9**	[redacted]	$318.7	$296.4	**$1,209.7**	[redacted]	$1,241.3	$1,167.3
Other Operating Revenues	**6.3**	[redacted]	4.1	6.8	**23.3**	[redacted]	15.7	23.9
Total Operating Revenues	**$289.2**	[redacted]	$322.8	$303.2	**$1,233.0**	[redacted]	$1,257.0	$1,191.2

Note:

1. Reclassifications have been made to the Test Year 2009 numbers in order to report amounts using the same line items used for US GAAP reporting purposes. The amounts used for the Test Year 2009 numbers are compliant with Canadian GAAP only.

Operating, Maintenance and General (Regulated)

For the millions of Canadian dollars	Three months ended December 31				Twelve months ended December 31			
	Actual 2011	[redacted]	*Test Year 2009*	*Prior Year 2010 (as adjusted)*	***Actual 2011***	[redacted]	*Test Year 2009*	*Prior Year 2010 (as adjusted)*
Corporate Groups	**$12.9**	[redacted]	$11.3	$12.6	**$51.0**	[redacted]	$44.8	$47.4
Power Production	**30.1**	[redacted]	22.2	26.2	**108.5**	[redacted]	88.8	94.2
Technical & Construction	**3.8**	[redacted]	0.8	3.4	**13.6**	[redacted]	3.5	11.7
Customer Operations	**17.7**	[redacted]	16.7	19.7	**69.1**	[redacted]	66.6	72.6
Customer Service	**13.4**	[redacted]	7.7	8.1	**40.0**	[redacted]	30.7	34.4
Corporate Adjustments	**(4.1)**	[redacted]	(3.8)	(4.4)	**(19.6)**	[redacted]	(16.2)	(22.5)
Total Operating, Maintenance and General	**$73.8**	[redacted]	$54.9	$65.6	**$262.6**	[redacted]	$218.2	$237.8

Note:

1. Reclassifications have been made to the Test Year 2009 numbers in order to report amounts using the same line items used for US GAAP reporting purposes. The amounts used for the Test Year 2009 numbers are compliant with Canadian GAAP only.

Summary of Unregulated Adjustments

As at	December 31
millions of Canadian dollars	2011

Unregulated Retained Earnings

Unregulated retained earnings - December 31, 2010	$57.6
Donations and sponsorships	1.2
Director share units/performance share units	1.6
Management fees	0.5
Unregulated portion of management incentive	2.7
New Page natural gas gain	(0.2)
FAM incentive	4.0
Depreciation expense, unregulated assets	0.3
Other	0.2
Income taxes, unregulated adjustments	(2.5)
Subtotal	7.8
Unregulated retained earnings - December 31, 2011	**$65.4**

Unregulated Property, Plant and Equipment

Kentville Electric Purchase Price Discrepancy Goodwill	$2.3
Combustion Turbine Purchase Price Discrepancy	3.8
Unregulated Portion of Digby Wind Project	0.9
Unregulated Land	1.0
Unregulated Portion of Lower Water Street	11.3
Burnside Natural Gas Conversion Project	2.8
Unregulated Portion of Tufts Cove 6 Project	1.9
Total unregulated property, plant and equipment	**$24.0**

Unregulated Deferred Income Taxes

Increase to current deferred income taxes liability related to unregulated expenditures	$2.5
Decrease to long-term deferred income taxes liability related to unregulated expenditures	(0.2)
Total unregulated deferred income taxes	**$2.3**

Unregulated Due from Related Parties

Effect of unregulated adjustments	**$91.7**

Regulated Return on Equity December 31, 2011

Millions of Canadian dollars

As of	Regulated Equity	Regulated Capitalization
December 31, 2010	$1,258.3	$3,299.5
March 31, 2011	1,362.5	3,401.0
June 30, 2011	1,381.7	3,455.3
September 30, 2011	1,404.7	3,412.8
December 31, 2011	1,404.4	3,469.8
Total	$6,811.6	$17,038.4
Average (Five Quarters)	**$1,362.3**	**$3,407.7**
Average Common Equity (Five Quarters)		**40.0%**
Regulated Net Earnings - December 31, 2011	**$131.3**	
Regulated ROE (Regulated Net Earnings/Average Regulated Common Equity)	**9.6%**	

Regulated Return on Equity is calculated at year-end and included in the fourth quarter and annual regulated financial statements.

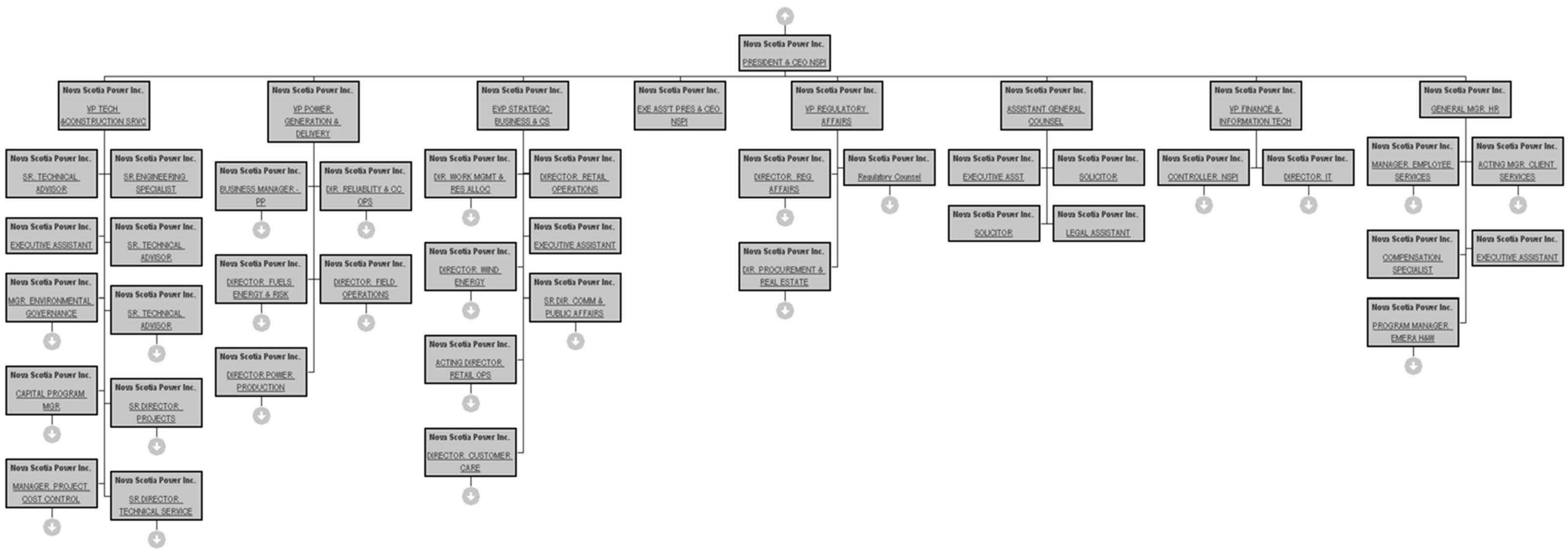
Requirement:

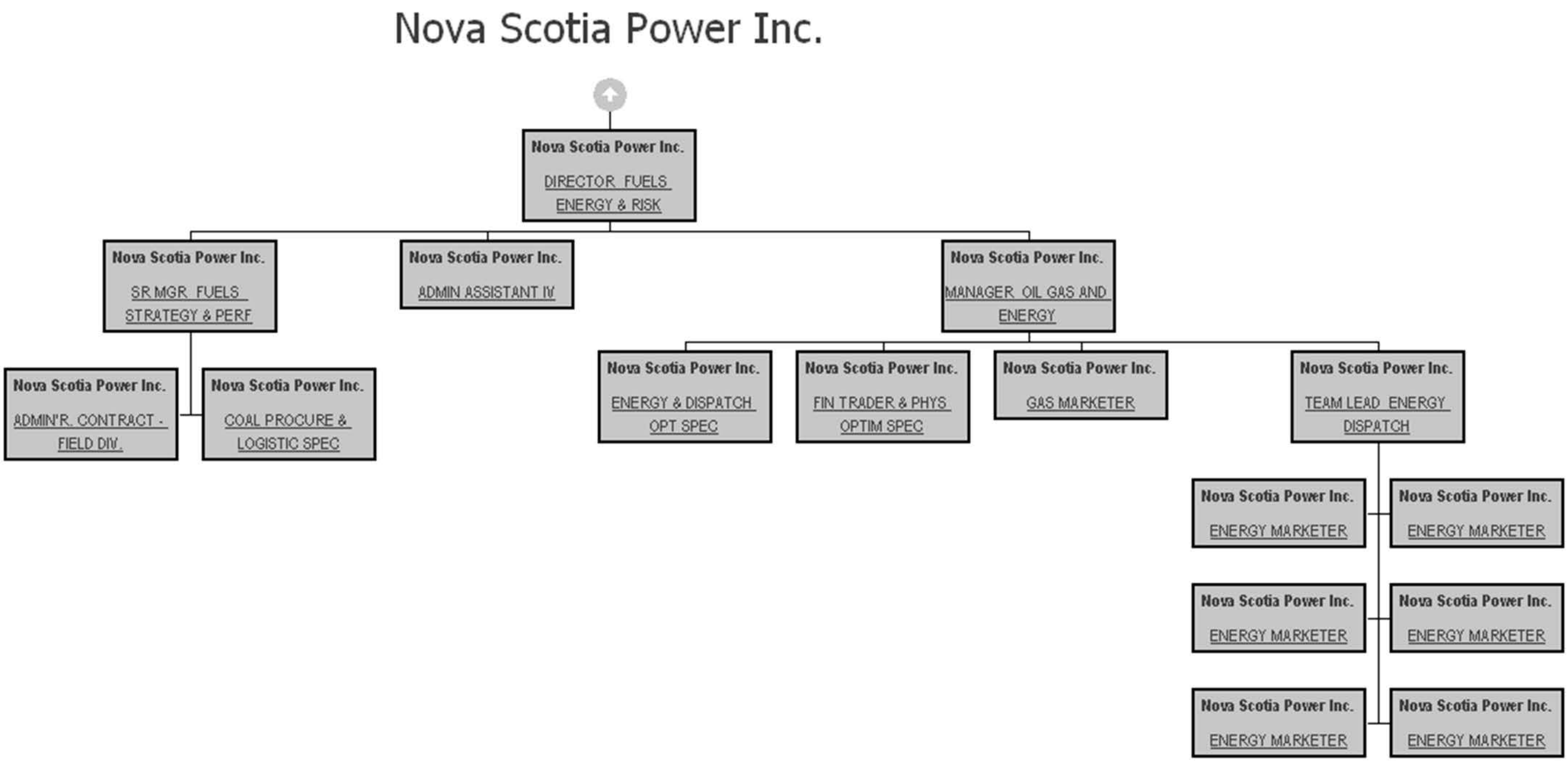
Current organization chart of NSPI showing all positions reporting no further than two levels down from the President and CEO, including a full organizational chart for the positions reporting to the Director, Fuels, Energy, and Risk Management.

Submission:

Please refer to Attachments 1 and 2.

Nova Scotia Power Inc.





Nova Scotia Power Inc.
Nova Scotia Power Inc.
DIRECTOR FUELS ENERGY & RISK
Nova Scotia Power Inc.
SR MGR FUELS STRATEGY & PERF
Nova Scotia Power Inc.
ADMIN ASSISTANT IV
Nova Scotia Power Inc.
MANAGER OIL GAS AND ENERGY
Nova Scotia Power Inc.
ADMIN'R. CONTRACT - FIELD DIV.
Nova Scotia Power Inc.
COAL PROCURE & LOGISTIC SPEC
Nova Scotia Power Inc.
ENERGY & DISPATCH OPT SPEC
Nova Scotia Power Inc.
FIN TRADER & PHYS OPTIM SPEC
Nova Scotia Power Inc.
GAS MARKETER
Nova Scotia Power Inc.
TEAM LEAD ENERGY DISPATCH
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Nova Scotia Power Inc.
ENERGY MARKETER

Requirement:

Copy of latest OM&G review undertaken since last rate filing.

Submission:

Please refer to Confidential Attachment 1.

Requirement:

Listing of all assets (by function) (length of transmission lines by voltage class, length of distribution lines by voltage, number of substation, et.)

Submission:

Please refer to Attachment 1.

Nova Scotia Power Inc.

1	**Steam**
2	Lingan 1 & 2
3	Lingan 3 & 4
4	Lingan Common
5	Point Aconi
6	Point Tupper
7	Trenton 5
8	Trenton 6
9	Trenton Common
10	Tufts Cove 1
11	Tufts Cove 2
12	Tufts Cove 3
13	Tufts Cove 6
14	Tufts Cove Common
15	Point Tupper Marine Terminal
16	
17	**Hydro**
18	Wreck Cove - Unit One
19	Wreck Cove - Unit Two
20	Gisborne
21	Avon # One - Unit One
22	Avon # Two - Unit Two
23	Methals
24	Hollow Bridge
25	Lumsden
26	Hell's Gate - Unit One
27	Hell's Gate - Unit Two
28	White Rock
29	Nictaux
30	Paradise
31	Ridge
32	Fourth Lake
33	Sissiboo
34	Weymouth - Unit One
35	Weymouth - Unit Two
36	Tusket - Unit One
37	Tusket - Unit Two
38	Tusket - Unit Three
39	Gulch
40	Lequille
41	Annapolis
42	Mersey
43	Roseway - Unit One
44	Roseway - Unit Two
45	Harmony
46	Mill Lake - Unit One
47	Mill Lake - Unit Two
48	Sandy Lake - Unit One
49	Sandy Lake - Unit One
50	Tide Water - Unit One
51	Tide Water - Unit Two
52	Fall River
53	Malay Falls - Unit Four
54	Malay Falls - Unit Five
55	Malay Falls - Unit Six
56	Ruth Falls - Unit One
57	Ruth Falls - Unit Two
58	Ruth Falls - Unit Three
59	Dickie Brook - Unit One
60	Dickie Brook - Unit Two
61	
62	**Other Production Plant**
63	Burnside Gas Turbines
64	Tusket Gas Turbines
65	Victoria Junction Turbines
66	Tufts Cove 4
67	Tufts Cove 5
68	
69	**Wind Turbine**
70	Little Brook
71	Grand Etang
72	Nuttby Wind Farm
73	Pt. Tupper Wind Farm
74	Digby Wind Farm
75	

	(1) Kms of Line	Voltage
Transmission	1,675	69kV
	1,898	138kV
	1,244	230kV
	492	345kV
	5,308	
Distribution	10,873	25KV
	14,704	12KV
	878	4KV
	26,455	

Nova Scotia Power has approximately 230 substations associated with the Transmission & Distribution systems. Other assets associated with the Transmission and Distribution system include land rights, towers, poles and fixtures, transformers, meters and street lighting and signal systems.

General Property

Nova Scotia Power has general property including land rights, roads, bridges, structures and improvements, office furniture, computer hardware and software, transportation, tools, stores, shop, garage, communications, mining and other equipment.

Requirement:

Test year Power Production unit maintenance schedule of all units including hydro, and tidal, submitted as a Gantt chart.

Submission:

Please refer to Confidential Attachments 1 and 2 for 2013 and 2014, respectively.

Requirement:

Breakdown of generating units by type showing in service date, net capacity, fuel type, heat rate, contribution to system peak, contribution towards annual energy (include IPP and purchased power).

Submission:

Please refer to Partially Confidential Attachments 1 and 2 for 2013 and 2014, respectively.

Standardized Filing Requirements for Fuel - Generating Units by Type
Year 2013

	Fuel Type	In Service Year	Net Operating Capacity (MW)	Net Avg. Heat Rate (Btu/kwh)	2013 Annual Energy (GWh)
Thermal Units					
Tufts Cove 1	Oil / Natural Gas	1965	81	[redacted]	350
Tufts Cove 2	Oil / Natural Gas	1972	93	[redacted]	465
Tufts Cove 3	Oil / Natural Gas	1976	147	[redacted]	1027
Trenton 5	Coal / Petcoke	1969	152	[redacted]	496
Trenton 6	Coal / Petcoke	1991	155	[redacted]	1164
Pt. Tupper 2	Coal / Petcoke	1973	152	[redacted]	906
		Coal Conv. 1987		[redacted]	
Lingan 1	Coal / Petcoke	1979	153	[redacted]	283
Lingan 2	Coal / Petcoke	1980	153	[redacted]	85
Lingan 3	Coal / Petcoke	1983	153	[redacted]	739
Lingan 4	Coal / Petcoke	1984	153	[redacted]	285
Pt. Aconi 1	Petcoke / Coal	1994	172	[redacted]	1211
Point Tupper Biomass	Biomass	2013	61	[redacted]	323
		Total Thermal	**1564**		**7336**
Combustion Turbines					
Tufts Cove 4	Natural Gas	2003	49	[redacted]	
Tufts Cove 5	Natural Gas	2005	49	[redacted]	
Tufts Cove 6	Natural Gas Combined Cycle	2011	50	[redacted]	878
Tusket 1	Light Oil	1971	24	[redacted]	1
Burnside 1	Light Oil	1976	33	[redacted]	3
Burnside 2	Light Oil	1976	33	[redacted]	2
Burnside 3	Light Oil	1976	33	[redacted]	1
Burnside 4	Light Oil	1976	33	[redacted]	0
Victoria Junction 1	Light Oil	1976	33	[redacted]	1
Victoria Junction 2	Light Oil	1975	33	[redacted]	0
		Total CT's	**371**		**885**
Hydro and Wind Systems	**Installed Capacity (MW)**		**Firm Capacity (MW)**		**Energy (GWh)**
Wreck Cove		1978	230		305
Annapolis Tidal		1984	3.7		27
Other Hydro		1929-2002	163.5		653
Little Brook	0.60	2003	0.2		2
Grand Etang	0.70	2003	0.2		2
Digby	30	2011	9.9		110
Nuttby Mountain	50.6	2011	16.7		140
Total Hydro/ Wind			**424**		**1239**
Independent Power Producers	**Installed Capacity (MW)**		**Firm Capacity (MW)**		**Energy (GWh)**
Independent Power Producers - Other	26.8		26.8	Contract IPPs (pre 2001)	165
Independent Power Producers - Wind	259.5		85.6	Renewables IPPs (post 2001)	733
Imported Power				Import Purchases	394
NS Power Total Firm Capacity (MW)			**2472**	**Total Purchases**	**1291**
				Total Annual Energy	**10751**

Note: NS Power has 46.69% ownership in the Point Tupper Wind Farm at the time this document was compiled. The full amount of this wind farm is reflected in the Independent Power Producers - Wind Category.

2013 Forecast Breakdown of Assets at the Time of Peak	
	MW
Peak (February, Tuesday, hour ending 19:00)	2098
Thermal contribution	1351
Hydro contribution	378
IPP and NSP wind contribution	81
Imports contribution	288
TOTAL	2098

Standardized Filing Requirements for Fuel - Generating Units by Type
Year 2014

	Fuel Type	In Service Year	Net Operating Capacity (MW)	Net Avg. Heat Rate (Btu/kwh)	2014 Annual Energy (GWh)
Thermal Units					
Tufts Cove 1	Oil / Natural Gas	1965	81	[redacted]	52
Tufts Cove 2	Oil / Natural Gas	1972	93	[redacted]	156
Tufts Cove 3	Oil / Natural Gas	1976	147	[redacted]	996
Trenton 5	Coal / Petcoke	1969	152	[redacted]	856
Trenton 6	Coal / Petcoke	1991	155	[redacted]	1185
Pt. Tupper 2	Coal / Petcoke	1973	152	[redacted]	1089
		Coal Conv. 1987		[redacted]	
Lingan 1	Coal / Petcoke	1979	153	[redacted]	201
Lingan 2	Coal / Petcoke	1980	153	[redacted]	59
Lingan 3	Coal / Petcoke	1983	153	[redacted]	798
Lingan 4	Coal / Petcoke	1984	153	[redacted]	247
Pt. Aconi 1	Petcoke / Coal	1994	172	[redacted]	1222
Point Tupper Biomass	Biomass	2013	61	[redacted]	435
		Total Thermal	**1564**		**7297**
Combustion Turbines					
Tufts Cove 4	Natural Gas	2003	49	[redacted]	
Tufts Cove 5	Natural Gas	2005	49	[redacted]	
Tufts Cove 6	Natural Gas Combined Cycle	2011	50	[redacted]	802
Tusket 1	Light Oil	1971	24	[redacted]	0
Burnside 1	Light Oil	1976	33	[redacted]	2
Burnside 2	Light Oil	1976	33	[redacted]	1
Burnside 3	Light Oil	1976	33	[redacted]	1
Burnside 4	Light Oil	1976	33	[redacted]	1
Victoria Junction 1	Light Oil	1976	33	[redacted]	0
Victoria Junction 2	Light Oil	1975	33	[redacted]	0
		Total CT's	**371**		**808**
Hydro and Wind Systems	**Installed Capacity (MW)**		**Firm Capacity (MW)**		**Energy (GWh)**
Wreck Cove		1978	230		305
Annapolis Tidal		1984	3.7		27
Other Hydro		1929-2002	163.5		653
Little Brook	0.60	2003	0.2		2
Grand Etang	0.70	2003	0.2		2
Digby	30	2011	9.9		110
Nuttby Mountain	50.6	2011	16.7		140
Total Hydro/ Wind			**424**		**1239**
Independent Power Producers	**Installed Capacity (MW)**		**Firm Capacity (MW)**		**Energy (GWh)**
Independent Power Producers - Other	36.8		36.8	Contract IPPs (pre 2001)	220
Independent Power Producers - Wind	267.5		88.3	Renewables IPPs (post 2001)	783
Imported Power				Import Purchases	394
NS Power Total Firm Capacity (MW)			**2484**	**Total Purchases**	**1396**
				Total Annual Energy	**10740**

Note: NS Power has 46.69% ownership in the Point Tupper Wind Farm at the time this document was compiled. The full amount of this wind farm is reflected in the Independent Power Producers - Wind Category.

2014 Forecast Breakdown of Assets at the Time of Peak	
	MW
Peak (February, Tuesday, hour ending 19:00)	2093
Thermal contribution	1284
Hydro contribution	377
IPP and NSP wind contribution	144
Imports contribution	288
TOTAL	2093

Requirement:

Physical, chemical specification sheets for all fuels.

Submission:

Please refer to Attachment 1.

TECHNICAL SPECIFICATION - LOW SULPHUR COAL

Properties (As Received Basis)	Typical	Minimum	Maximum	Applicable ASTM Standard
Moisture	7%	-	9%	D3302
Free Moisture	-	-	3%	D3302
Ash	7%	-	9%	D3172
Sulphur	0.65%	-	1.10%	D3177
Volatile Matter	34%	30%	-	D3175
Calorific Value (Btu/lb.)	11,300	10,800	-	D5865
Grindability (HGI)	45-55	42	65	D409
Size (Topsize)	-	-	2” x 0	D4749
Size (Fines < 0.5 mm)	-	-	10%	D4749
Mercury				D6414-01

TECHNICAL SPECIFICATION – MID SULPHUR COAL

Properties (As Received Basis)	**Typical**	**Minimum**	**Maximum**	**Applicable ASTM Standard**
Moisture	7%	-	12%	D3302
Ash	7%	-	12%	D3172
Sulphur	-	-	3.5%	D3177
Volatile Matter	35%	30%	-	D3175
Calorific Value (Btu/lb.)		11,000	-	D5865
Grindability (HGI)	50-60	50	65	D409
Size (Topsize)	-	-	2” x 0	D4749
Size (Fines < 0.5 mm)	-	-	10%	D4749
Mercury				D6414-01
Chlorine			1100 ppm	D4208-02

TECHNICAL SPECIFICATION – PETROLEUM COKE

Type: Delayed Petroleum Coke, Shot Coke Only

Properties (As Received Basis)	**Typical**	**Minimum**	**Maximum**	**Applicable ASTM Standard**
Moisture	7%	-	9%	D4931
Ash	0.5%	0.2%	1.0%	D4422
Sulphur	4-6%	-	6.5%	D1552
Volatile Matter	10%	8%	-	D4421
Calorific Value (Btu/lb.)	14,000	13,900	-	D5865
Grindability (HGI)	40	30	55	D5003
Size (Topsize)	-	-	2” x 0	D5709
Size (Fines < 0.5 mm)	-	-	12%	D5709
Vanadium, ppm	800		1900	D5056
Nickel, ppm	100		750	D5056
Mercury				D6414-01
Chlorine			1100 ppm	D4208-02

CONTRACT STANDARD
SPECIFICATION

NSPI Combustion Turbine
Distillate Specification for Product Delivered
March 1 – November 30

PROPERTY	MIN / MAX	ASTM TEST METHOD
Appearance	Clear and Bright	Visual
Density, kg/m3	0.881 max	D1298
Distillation 90% Recovered	360.0 max	D86
Cloud Point, Degree C	Report (note 1)	D2500
Pour Point, Degrees C	Report (note 1)	D97
Viscosity @ 40 C, cst	1.3 min – 3.6 max	D445
Cetane Number	40 min	D613
Sulfur, wt %	0.1 max	D1552
Corrosion – Copper – 3 hrs @ 50 C	No. 1 max	D130
Micro Carbon Residue 10% Bottoms % Mass	0.2 max	D4530
Flash, Degrees C	40 min	D93
Water and Sediment, Vol %	0.05 max	D1796
Ash, wt %	0.01 max	D482
Trace Metals, ppm by wt%		D3605
Vanadium	0.2 max	
Sodium plus Potassium	0.6 max	
Calcium	2.0 max	
Lead	0.1 max	

Notes:

1. Operability of the fuel shall meet seasonal conditions. An operability schedule must be submitted with the tender.

Effective Date: May 1, 2003
Updated: November 1, 2009

CONTRACT STANDARD
SPECIFICATION

NSPI Combustion Turbine
Distillate Specification for Product Delivered
December 1 – February 28

PROPERTY	MIN / MAX	ASTM TEST METHOD
Appearance	Clear and Bright	Visual
Density, kg/m3	0.850 max	D1298
Distillation 90% Recovered	290.0 max	D86
Cloud Point, Degree C	-34 max	D2500
Pour Point, Degrees C	Report	D97
Viscosity @ 40 C, cst	1.1 min – 1.8 max	D445
Cetane Number	40 min	D613
Sulfur, wt %	0.1 max	D1552
Corrosion – Copper – 3 hrs @ 50 C	No. 1 max	D130
Micro Carbon Residue 10% Bottoms % Mass	0.1 max	D4530
Flash, Degrees C	40 min	D93
Water and Sediment, Vol %	0.05 max	D1796
Ash, wt %	0.01 max	D482
Trace Metals, ppm by wt%		D3605
Vanadium	0.2 max	
Sodium plus Potassium	0.6 max	
Calcium	2.0 max	
Lead	0.1 max	

Effective Date: May 1, 2003
Updated: November 1, 2009

HFO QUALITY SPECIFICATION

Property	Requirement	ASTM Test
Gravity, ^{0}API- Apr 1 to Dec 31 Gravity, ^{0}API- Jan 1 to Mar 31	min. 9.0 min. 9.5	D1298 D1298
Saybolt Viscosity, Furol @ 50 ^{0}C	min. 150 max. 300	D445, D2161
Flash Point, ^{0}C (^{0}F)	min. 66 (150)	D93
Sulphur, wt. %	max. 2.2 (or 1.0)	D4294
Water by Distillation, vol. %	max. 1.0	D95
Compatibility, spot	max. 1	D4740
Hydrogen Sulphide, vol. ppm *(The preceding seven Properties are referenced in Section 13.8 (a))*	200	Exxon AM-S90-003
Gross Heat of Combustion, MMBtu/Bbl	6.325	D240
Ash, wt. %	max. 0.10	D482
Sediment by Extraction, wt. %	max. 0.25	D473
Sediment by Hot Filtration, wt. %	max. 0.1	D4870
(1) Vanadium, wt. ppm	max. 300	D5863A/B (1)
Sodium, wt. ppm	max. 50	D5863B
Ashphaltenes, wt. %	max. 10	IP143
Pour Point, ^{0}C (^{0}F)	max. 21 (70)	D97

Notes: 1)Test method ASTM-D-5863(B) will be used at discharge port to determine if discharge should be delayed while test method 5863(A) is performed. Test method ASTM-D-5863(A) will be used for pricing calculations at discharge port, and will be binding in the event of a dispute.

Technical Specifications – Natural Gas

Total Heating Value

(a) Natural gas received or delivered hereunder shall have a Total Heating Value below 36 MJ/m^3.

Composition

(a) Oxygen. The gas shall not have an uncombined oxygen content in excess of two-tenths (0.2) of one percent (1%) by volume, and both parties shall make every reasonable effort to keep the gas free from oxygen.

(b) Non-Hydrocarbon Gases. The gas shall not contain more than four percent (4%) by volume, of a combined total of non-hydrocarbon gases (including carbon dioxide and nitrogen); it being understood, however, that the total carbon dioxide content shall not exceed three percent (3%) by volume.

(c) Liquids. The gas shall be free of water and hydrocarbons in liquid form at the temperature and pressure at which the gas is received and delivered.

(d) Hydrogen Sulphide. The gas shall not contain more than six (6) milligrams of hydrogen sulphide per one (1) Cubic Meter.

(e) Total Sulphur. The gas shall not contain more than four-hundred and sixty (460) milligrams of total sulphur, excluding any mercaptan sulphur, per one (1) Cubic Meter.

(f) Temperature. The gas shall not have a temperature of more than forthy-nine degrees (49^o) Celsius.

(g) Water Vapor. The gas shall not contain in excess of eighty (80) milligrams of water vapor per one (1) Cubic Metre.

(h) Liquefiable Hydrocarbons. The gas shall not contain liquid hydrocarbons or hydrocarbons liquefiable at temperatures warmer than minus nine degrees (-9^{o}) Celsius and normal pipeline operating pressures of between 690 and 9930 kPag.

(i) Microbiological Agents. The gas shall not contain any microbiological organism, active bacteria or bacterial agent capable of contributing to or causing corrosion and/or operational and/or other problems.

Requirement

IPP contract details.

Submission:

Please refer to Confidential Attachment 1.

Requirement:

Reliability Statistics for fossil fleet, and customer outage indices for NSPI and comparison to latest CEA all Canada values.

Submission:

Please refer to Attachment 1.

Performance Factor:	**Availability**					
Annual Hours:	**8760**	**8784**	**8760**	**8760**	**8760**	**CEA**
Year:	**2007 Actual**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2006-2010**
Plant						
Pt. Aconi	92.90%	88.90%	92.80%	87.60%	87.80%	
Tufts Cove #1	87.90%	79.60%	54.00%	94.00%	83.40%	
Tufts Cove #2	89.10%	84.30%	68.80%	92.30%	89.70%	
Tufts Cove #3	82.50%	72.80%	74.30%	69.60%	85.20%	
Tufts Cove #4				91.60%	97.80%	
Tufts Cove #5				72.60%	57.40%	
Tufts Cove #6						
PT. Tupper #2	98.90%	89.90%	90.30%	94.70%	57.30%	
Trenton #5	90.90%	94.50%	65.80%	65.60%	92.10%	
Trenton #6	91.40%	87.30%	93.00%	85.50%	94.20%	
Lingan #1	96.20%	80.70%	96.90%	81.00%	97.30%	
Lingan #2	89.60%	93.50%	90.30%	91.40%	90.20%	
Lingan #3	94.60%	93.80%	88.70%	96.00%	91.90%	
Lingan #4	91.70%	80.10%	86.00%	97.80%	88.90%	
Fossil Fleet Availability	**91.40%**	**87.60%**	**82.30%**	**86.90%**	**87.10%**	**79.71%**

Definition: Availability is not a reported CEA measure. It is comparable to the Capability Factor CbF (%), which is the complement of the Incapability Factor. * CEA Availability is calculated here as (100% - ICbF).

Performance Factor: **MOF**

Annual Hours:	**8760**	**8784**	**8760**	**8760**	**8760**	**CEA**
Year:	**2007 Actual**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2006-2010**
Plant						
Pt. Aconi	0.38%	1.38%	2.82%	2.92%	0.22%	
Tufts Cove #1	1.62%	0.41%	13.14%	2.27%	3.80%	
Tufts Cove #2	3.84%	5.01%	0.77%	3.54%	3.27%	
Tufts Cove #3	2.63%	8.79%	1.54%	4.15%	4.87%	
Tufts Cove #4				0.02%	0.44%	
Tufts Cove #5				0.41%	0.06%	
Tufts Cove #6				n/a	n/a	
PT. Tupper #2	0.00%	1.57%	2.82%	0.00%	0.41%	
Trenton #5	0.74%	0.80%	0.34%	2.91%	0.67%	
Trenton #6	0.00%	0.79%	4.38%	0.02%	0.89%	
Lingan #1	0.32%	0.45%	0.68%	0.00%	0.00%	
Lingan #2	0.00%	0.00%	0.00%	0.00%	0.20%	
Lingan #3	0.00%	0.00%	0.00%	0.00%	1.26%	
Lingan #4	0.00%	0.00%	0.00%	0.88%	0.00%	
Fossil Fleet MOF	**0.95%**	**0.92%**	**1.75%**	**1.32%**	**1.41%**	**2.67%**

Definition: MOF (%) : the Maintenance Outage Factor is computed by dividing the number of maintenance outage hours by the number of Unit Hours times 100.

Performance Factor:	**DAFOR**					
Annual Hours:	**8760**	**8784**	**8760**	**8760**	**8760**	**CEA**
Year:	**2007 Actual**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2006-2010**
Plant						
Pt. Aconi	0.58%	4.56%	6.39%	6.74%	6.23%	
Tufts Cove #1	3.06%	1.98%	37.65%	1.34%	2.51%	
Tufts Cove #2	0.09%	0.24%	2.26%	0.36%	1.39%	
Tufts Cove #3	1.87%	12.05%	22.68%	3.74%	2.70%	
Tufts Cove #4			21.96%	3.84%	1.24%	
Tufts Cove #5			8.76%	1.06%	49.48%	
Tufts Cove #6				n/a	n/a	
PT. Tupper #2	1.18%	1.84%	6.00%	0.12%	1.76%	
Trenton #5	2.27%	8.42%	16.63%	22.05%	15.82%	
Trenton #6	3.20%	1.72%	6.39%	9.45%	2.68%	
Lingan #1	2.69%	7.80%	3.10%	3.56%	2.69%	
Lingan #2	2.78%	3.62%	2.39%	4.20%	2.31%	
Lingan #3	4.89%	6.34%	4.71%	4.03%	0.70%	
Lingan #4	1.87%	5.17%	0.03%	4.79%	1.58%	
Fossil Fleet DAFOR	**2.32%**	**5.30%**	**9.30%**	**5.11%**	**3.11%**	**10.78%**

Definition: DAFOR (%): the Derated Adjusted Forced Outage Rate is the ratio of Equivalent Forced Outage Time to Equivalent Forced Outage Time plus Total Equivalent Operating Time.

Customer Outage Indices

	NSPI All-In Data			CEA REGION 2		
YEAR	NSPI SAIFI	NSPI SAIDI	NSPI CAIDI	CEA SAIFI	CEA SAIDI	CEA CAIDI
2007	3.98	14.17	3.56	2.68	7.29	2.72
2008	4.15	11.29	2.72	2.76	8.56	3.10
2009	2.86	5.80	2.03	2.31	5.31	2.30
2010	4.36	17.67	4.06	2.54	7.00	2.76
2011	3.73	7.90	2.12	N/A	N/A	N/A

Requirement:

Number of customers by rate class.

Submission:

Forecasted average number of customers by rate class:

Class	2013	2014
Domestic	452,558	456,991
General	35,299	35,476
Industrial	2,462	2,457
Other	9,512	9,611
Total	499,831	504,535

Requirement:

Electronic link to latest Hydro Quebec report "Comparison of Electric Prices in Major North American Cities".

Submission:

http://www.hydroquebec.com/publications/en/comparison_prices/pdf/comp_2011_en.pdf

Requirement:

Presentations made by NSPI/Emera to Analysts and Bondholders, within the last year, on behalf of NSPI and Emera (to the extent NSPI is included in the Emera presentation) and copies of any reports NSPI has received from financial analysts or bondholders since the last rate filing.

Submission:

Presentation to Bond Rating Agencies: Please refer to Confidential Attachment 1 for presentations NS Power has made to Bond Rating Agencies in the last year.

Presentations to Investors: Please refer to Confidential Attachment 2 for nine presentations made by Emera. Emera has additional presentations however the information related to NS Power is similar to the information in the nine Emera presentations provided. Additional presentations can be found on Emera's website at www.emera.com. NS Power has not made any presentations to Investors within the last year.

Bond Rating Reports: Please refer to Confidential Attachment 3.

Reports from Equity Analysts: Please refer to Confidential Attachment 4.

Requirement:

Most recent Emera Proxy statement.

Submission:

Please refer to Attachment 1.

NS Power's 2011 Proxy has not yet been released. We expect it will be released within the next week.

EMERA INCORPORATED

NOTICE OF ANNUAL MEETING OF COMMON SHAREHOLDERS WEDNESDAY, MAY 5, 2010

AND

MANAGEMENT INFORMATION CIRCULAR

Notice of Annual Meeting

The annual meeting of the common shareholders of Emera Incorporated will be held at the World Trade and Convention Centre, 1800 Argyle Street, Halifax, Nova Scotia on Wednesday, May 5, 2010 at 2:00 p.m. (Halifax time) for the purposes of:

1. Electing Directors to serve until the next annual meeting of shareholders;
2. Appointing Auditors;
3. Authorizing the Directors to establish the Auditors' fee; and
4. Transacting such other business as may properly come before the Meeting.

Common shareholders of record as of the close of business on Friday, March 19, 2010 are entitled to vote at and participate in the business of the Meeting.

By Order of the Board of Directors,

"Stephen D. Aftanas"
Stephen D. Aftanas
Corporate Secretary

Halifax, Nova Scotia, Canada
February 12, 2010

As a shareholder, it is important that you vote. Common shareholders are encouraged to return their proxy as soon as possible. A postage-paid, pre-addressed envelope is provided. As an alternative, shareholders may choose to vote by telephone or the Internet as provided for on the proxy. Proxies must be received prior to the close of business on Tuesday, May 4, 2010.

Should you have any questions or comments, you may contact Emera Incorporated by writing to the Corporate Secretary, Emera Incorporated, P.O. Box 910, Halifax, Nova Scotia B3J 2W5 or by calling 1-800-358-1995 from anywhere in North America or 428-6060 within the Halifax-Dartmouth area.

Management Information Circular

Information as of March 15, 2010
(unless otherwise noted)

Solicitation of Proxies

This Management Information Circular (the "Circular") is furnished in connection with the solicitation of proxies by the Board of Directors and management of Emera Incorporated (the "Company" or "Emera") for use at the annual meeting (the "Meeting") of common shareholders (the "Shareholders") of the Company to be held on Wednesday, May 5, 2010 as set forth in the Notice of Annual Meeting (the "Notice").

Enclosed with this Circular is a proxy. The solicitation of proxies will be primarily by mail although proxies may also be solicited by telephone, facsimile, in writing, or in person, by Directors, Officers, or other employees or agents of the Company.

The Company wishes to have as many Shareholders vote as possible and has retained a proxy solicitation agent to assist with the solicitation of votes from Shareholders. The proxy solicitation agent will monitor the number of Shareholders voting and will contact Shareholders in order to ensure that a maximum vote is achieved. The cost of this solicitation will be borne by the Company and is expected to be approximately $60,000.

Appointment and Revocation of Proxies

The persons named in the enclosed proxy, John T. McLennan, Chair of the Board; and Christopher G. Huskilson, President and Chief Executive Officer, are Directors of the Company. Stephen D. Aftanas is Corporate Secretary of the Company.

In order for a proxy to be counted, it must be received prior to the close of business on Tuesday, May 4, 2010. For Canadian residents, a postage-paid, pre-addressed envelope is provided for this purpose. In order for your vote to be counted, you may:

vote by proxy via mail, the Internet or telephone;
or
attend the Meeting in person and submit your completed proxy;
or
attend the Meeting in person and vote by ballot.

Completion of a proxy gives discretionary authority to the proxyholder in respect of amendments to matters identified in the Notice and other matters that may properly come before the Meeting or any adjournment thereof. As of the date of this Circular, management of the Company knows of no such amendments or other matters to be presented for action at the Meeting.

If you appoint Mr. McLennan, Mr. Huskilson, or Mr. Aftanas as your proxyholder, they will vote, or withhold from voting, in accordance with your directions. **If you do not specify how you want your shares voted, they will vote "For" the:**

- **election of Directors named in this Circular;**
- **appointment of Ernst & Young, LLP as Auditors; and**
- **authorization of the Directors to establish the Auditors' fee.**

They will vote in accordance with their best judgement if any other matters are properly brought before the Meeting.

Shareholders may appoint any other person (who need not be a Shareholder) to represent them at the Meeting by inserting that person's name in the space provided on the accompanying proxy. The person whom you appoint is your proxyholder and must attend and vote at the Meeting in order for your vote to count.

Shareholders may revoke their proxy by giving written notification addressed to Stephen D. Aftanas, Corporate Secretary, 18th Floor, Barrington Tower, Scotia Square, P.O. Box 910, Halifax, Nova Scotia B3J 2W5, not later than the last business day preceding the day of the Meeting or any postponement or adjournment thereof or with the Chair of the Meeting on the day of the Meeting or any postponement or adjournment thereof or in any other manner permitted by law. If a proxy is revoked and not replaced by the close of business on Tuesday, May 4, 2010, the shares represented by such revoked proxy will not be counted and can only be voted in person by the Shareholder at the Meeting.

Record Date and Voting of Shares

The date for determining which Shareholders are entitled to receive Notice is Friday, March 19, 2010. This is called the "Record Date". Only Shareholders of record at the close of business on the Record Date will be entitled to vote. Each common share owned as of the Record Date entitles the holder to one vote.

To the knowledge of the Directors and Officers, as of the date of this Circular, no person owned or exercised control over more than ten percent of the outstanding common shares of the Company and the only outstanding voting shares were 113,331,282 common shares.

Beneficial (or Non-Registered) Shareholders

Shareholders who have shares registered in their own name are called registered shareholders. Shareholders who do not hold shares in their own name are called beneficial or non-registered shareholders.

If shares are listed in an account statement provided to a shareholder by a broker, then it is likely that those shares will not be registered in the shareholder's name but under the broker's name or under the name of an agent of the broker such as CDS Clearing and Depository Services Inc. or its nominee, the nominee for many Canadian brokerage firms.

There are two kinds of beneficial owners: (i) Objecting Beneficial Owners - those who object to their name being made known to the issuers of shares which they own and (ii) Non-Objecting Beneficial Owners - those who do not object to their name being made known to the issuers of the shares which they own.

Non-Objecting Beneficial Owners will receive a voting instruction form ("VIF") from Emera's registrar and transfer agent, Computershare Trust Company of Canada ("Computershare"). This is to be completed and returned to Computershare in the envelope provided. In addition, Computershare provides both telephone voting and Internet voting as described on the VIF.

Securities regulation requires brokers or agents to seek voting instructions from Objecting Beneficial Shareholders in advance of the Meeting. Objecting Beneficial Owners should be aware that brokers or agents can only vote shares if instructed to do so by the objecting beneficial shareholder. Your broker or agent (or their agent Broadridge) will have provided you with a VIF or form of proxy for purposes of obtaining your voting instructions. Every broker has its own mailing procedures and provides instructions for voting. Shareholders must follow those instructions carefully to ensure their shares are voted at the Meeting. **An objecting beneficial shareholder receiving a voting instruction form or proxy from a broker or agent cannot use that proxy to vote in person at the Meeting. To vote your shares at the meeting, the voting instruction form or proxy must be returned to the broker well in advance of the Meeting. If you wish to attend and vote your shares in person at the Meeting, follow the instructions for doing so provided by your broker or agent.**

Shareholder Proxy Materials

These Shareholder proxy materials are being sent to both registered and non-registered owners of the Company's shares. If you are a non-registered owner, and the Company or its agent has sent these materials directly to you, your name and address and information about your holding of shares, have been obtained in accordance with applicable securities regulatory requirements from the intermediary holding on your behalf.

Restrictions on Share Ownership and Voting

There are legislated restrictions on the ownership of the Company's voting shares. Common shares are the only voting shares at this time. No Shareholder may own or control, directly or indirectly, more than 15 percent of the outstanding voting shares. Shareholders who are not residents of Canada may not hold, in total, more than 25 percent of outstanding voting shares.

These restrictions may be enforced by limiting non-complying Shareholders' voting rights, dividend rights and transfer rights. Shareholders may be required, at any time, to furnish a statutory declaration to verify the number of shares held and/or residency in order to ensure compliance with these restrictions.

If you have any questions about share ownership and voting restrictions, please contact the Corporate Secretary.

Business of the Meeting

All resolutions placed before the Meeting must be approved by a majority of the votes cast.

1. **Election of the Board of Directors:** The 10 nominees proposed for election as Directors at the 2010 Meeting are identified under the section of this Circular entitled “Director Nominees”. The Company’s Articles of Association state that no more than two Directors may be current employees of the Company or an affiliate of the Company. The President and Chief Executive Officer, Christopher G. Huskilson, is the only nominee who is an employee of the Company.

   All nominees are currently Directors of the Company and have served as Directors from the dates set out under “Director Nominees” below. Each nominee has indicated his or her willingness to serve as a Director. Each Director elected at the Meeting will hold office until the next Annual Meeting of Shareholders.

   Mr. McLennan, Mr. Huskilson and Mr. Aftanas intend to vote "For" the 10 nominees unless a Shareholder specifies that their shares be withheld.

   <u>Majority Voting Policy for Directors</u>

   In February 2008, the Board of Directors adopted a Majority Voting Policy for Directors. For information about the Majority Voting Policy refer to the section of this Circular entitled “Statement of Corporate Governance Practices” under the heading “Majority Voting for Election of Directors”.

2. **Appointment of Auditors:** The Audit Committee pre-approves all services to be supplied by auditors and has reviewed the performance of Ernst & Young, LLP, including its independence, relating to the audit. Mr. McLennan, Mr. Huskilson and Mr. Aftanas intend to vote "For" the re-appointment of Ernst & Young, LLP as auditors of the Company to hold office until the close of the next Annual Meeting of Shareholders, unless a Shareholder specifies their shares be withheld from voting.

   Ernst & Young, LLP have been auditors of the Company since 1998 and its predecessor company since 1991.

3. **Auditors' Fee:** Mr. McLennan, Mr. Huskilson and Mr. Aftanas intend to vote "For" the authorization of Directors to establish the auditors' fee for 2010, unless a Shareholder specifies their shares be voted "Against" such matter. The Company is incorporated under the Nova Scotia *Companies Act*. Shareholder approval of this matter is required pursuant to the Act. The fees paid to Ernst & Young, LLP for services provided to the Company and certain subsidiaries for 2009 were as follows:

Audit Fees	$ 506,761
Audit-Related Fees	123,056
Tax Fees	592,180
	$1,221,997

Director Nominees

Emera’s Articles of Association and the Charter for the Nominating and Corporate Governance Committee assign the responsibility for recruiting and selecting nominees for election as Directors. The Committee reviews the experience and skill sets of the present Directors and assesses the profiled requirements needed to ensure that the Board is able to function effectively. The Committee evaluates issues which face, or will face, the Company and provides a plan of action necessary to ensure the Board expertise will be appropriate for Company activities.

The Committee uses the services of a qualified search consulting firm in order to assist it in identifying suitable new Director candidates. New Director candidates are met by at least the Chair of the Board, the Committee Chair, and the President and Chief Executive Officer, and in most cases by additional Directors. Reference checks and background checks may also be carried out on new Director candidates.

The information below identifies the proposed nominees, information about their experience, length of service on the Board if applicable, and share and/or deferred share unit ownership as of December 31, 2008 and December 31, 2009. The estimated value of their equity and deferred share unit holdings on December 31, 2009 is based on the closing price of Emera’s common shares on December 31, 2009 of $25.07 and the estimated value of their equity and deferred share unit holdings on December 31, 2008 is based on the closing price of Emera’s common shares on December 31, 2008 of $22.20.

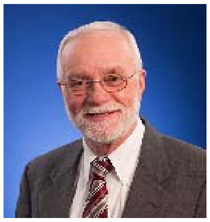
All nominees are required to meet share ownership guidelines, and the information below discusses each Director’s status under those guidelines. For further information on the non-employee Directors share ownership guidelines, see "Directors Share Ownership Guidelines" in the section of this Circular entitled "Statement of Corporate Governance Practices". For further information on the share ownership guidelines for Mr. Huskilson, see the heading "Executive Share Ownership Requirements" in the Statement of Executive Compensation later in this Circular.

All nominees, except Mr. Huskilson and Mr. Briggs, are not and have not been members of management or employees of the Company or any of its affiliates. Mr. Briggs has not been a member of management of an affiliate since 2001. A number of nominees are also Directors of public issuers and further information is contained below in the table entitled "Other Publicly-Traded Directorships". However, none of the nominees are Directors, officers or significant shareholders of an entity that has a relationship with the Company that could be perceived to materially interfere with their ability to act in the best interests of the Company. Based on this, all nominees are considered by the Board to be independent, except for Mr. Huskilson.

Nova Scotia Power Incorporated (NSPI) is a wholly-owned subsidiary of Emera and is referred to below in certain Director information.

The matrix below shows the Board's mix of skills and experience in nine categories important to the Company's business.

Skills and Experience	Director Nominees with Applicable Skills or Experience
CEO/Senior Executive - CEO or Senior Officer experience with large organization	9
Governance/Other Directorships - Director of public Company and/or significant governance role.	9
Customer/Stakeholder - Experience in managing stakeholder or represents customer group.	7
Energy Sector - Senior executive experience in the energy sector.	5
M&A/Growth Strategy - Senior executive experience with mergers, acquisitions and/or business growth strategy.	7
Compensation and Human Resources - Understanding and experience with human resources issues and compensation policies.	7
Financial - Financial literacy	10
Legal and Regulatory - Legal or regulatory experience.	6
Diversity - Gender, ethnic, geographic origin, experience in industry, public, private or non-profit sector.	9



Robert S. Briggs
Age: 66
Carrabassett Valley,Maine,U.S.A.
Director Since: 2001
Independent

Mr. Briggs has been a Director of the Company since October 2001 and has been a member of the Audit Committee since April 2002.

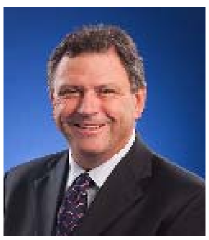
Mr. Briggs was the President and Chief Executive Officer of Bangor Hydro Electric Company from January 1991 to October 2001 and was a Director of Bangor Hydro from 1985 to October 2001. From October 2001 to October 2006, Mr. Briggs was a Director of Nova Scotia Power Incorporated.

Mr. Briggs graduated from the University of New Hampshire with a BA and from University of Maine School of Law with a JD.

Board/Committee Membership	Attendance	Total %	Public Board Membership During Last Five Years
- Board Member	8 of 8	100%	None
- Audit Committee Member	4 of 4	100%	

Securities Held:

Year Ended	Common Shares	DSUs	Value of Shares and DSUs	Status under Share Ownership Guidelines
2009	5250	Nil	$131,617	Mr. Briggs owns shares and DSUs valued at 75% of the requirement under the Guidelines. He has until September 2013 to meet the Share Ownership Guidelines.
2008	5250	Nil	$116,550	



Thomas W. Buchanan, F.C.A.
Age: 54
Calgary, Alberta
Director Since: 2009
Independent

Mr. Buchanan has been a Director of the Company since May 2009 and has been a member of the Audit Committee and the Nominating and Corporate Governance Committee since May 2009.

Mr. Buchanan is a Director and the President and Chief Executive Officer of Provident Energy Trust, an energy income trust in Calgary, Alberta that owns and manages an oil and gas production business and a natural gas liquids midstream services and marketing business. Mr. Buchanan is a Director of Hawk Exploration Ltd. and Athabasca Oil Sands Corp.

Mr. Buchanan is a Fellow of the Chartered Accountants. He graduated from the University of Calgary with a Bachelor of Commerce degree.

Board/Committee Membership	Attendance	Total %	Public Board Membership During Last Five Years
- Board Member	5 of 5	100%	Provident Energy Trust, Breitburn Energy Partners LP, Churchill Energy Inc., Hawk Exploration Ltd.
- Audit Committee Member	2 of 2	100%	
- Nominating and Corporate Governance Committee Member	2 of 2	100%	

Securities Held:

Year Ended	Common Shares	DSUs	Value of Shares and DSUs	Status under Share Ownership Guidelines
2009	Nil	2055	$51,518	Mr. Buchanan owns shares and DSUs valued at 29% of the requirement under the Guidelines. He became a Board member in May 2009, therefore he has until May 2014 to meet the Share Ownership Guidelines.
2008	N/A	N/A	N/A	

George A. Caines, Q.C.
Age: 72
Halifax, Nova Scotia
Director Since: 2009
Independent

Mr. Caines was appointed a Director of the Company on September 25, 2009 and was previously a Director of the Company from September 1998 to May 2007 and was Chair of the Audit Committee from May 2000 to May 2006. Mr. Caines has been the Chair of the Board of Nova Scotia Power Incorporated since May 2009 and has been a Director of Nova Scotia Power Incorporated since April 1995.

Mr. Caines is a partner with the Halifax offices of the law firm Stewart McKelvey.

Mr. Caines graduated from University King's College with a B.A. and graduated from Dalhousie University with an LL.B.

Board/Committee Membership	Attendance	Total %	Public Board Membership During Last Five Years
- Board Member	2 of 2	100%	None

Securities Held:

Year Ended	Common Shares	DSUs	Value of Shares and DSUs	Status under Share Ownership Guidelines
2009	5,420	15,643	$528,049	Mr. Caines owns shares and DSUs valued at 301% of the requirement under the Guidelines, therefore, Share Ownership Guidelines are met.
2008	4,531	14,910	$431,590	

Gail Cook-Bennett, C.M
Age: 69
Toronto, Ontario
Director Since: 2004
Independent

Dr. Cook-Bennett has been a Director of the Company since November 2004. Since November 2004 she has been a member of the Nominating and Corporate Governance Committee and has been Committee Chair since May 2006. She was a member of the Audit Committee from May 2005 to May 2007. From November 2004 to October 2006, Dr. Cook-Bennett was a Director of Nova Scotia Power Incorporated.

Dr. Cook-Bennett is Chair of Manulife Financial Corporation, an insurance company which provides life insurance, group life and health insurance, long-term care services, pension products, annuities, and mutual funds in international markets. Prior to October 2008 she was Chair of the Canada Pension Plan Investment Board which has responsibility for investing Canada Pension Plan contributions. Dr. Cook-Bennett is a Fellow of the Institute of Corporate Directors.

Dr. Cook-Bennett graduated from the University of Michigan with a Ph.D. in Economics. She is a Fellow with the Institute of Corporate Directors.

Board/Committee Membership	Attendance	Total %	Public Board Membership During Last Five Years
- Board Member	7 of 8	87%	Manulife Financial Corporation
- Nominating and Corporate Governance Committee Chair	3 of 3	100%	Petro Canada

Securities Held:

Year Ended	Common Shares	DSUs	Value of Shares and DSUs	Status under Share Ownership Guidelines
2009	1,000	13,586	$365,671	Dr. Cook-Bennett owns shares and DSUs valued at 208% of the requirement under the Guidelines, therefore, Share Ownership Guidelines are met.
2008	1,000	10,243	$249,595	

Allan L. Edgeworth
Age: 59
Calgary, Alberta
Director Since: 2005
Independent

Mr. Edgeworth has been a Director of the Company since November 2005. He has been a member of the Management Resources and Compensation Committee since February 2006 and a member of the Audit Committee since April 2008. He was a member of the Nominating and Corporate Governance Committee from May 2007 to April 2008. From November 2005 to October 2006, Mr. Edgeworth was a Director of Nova Scotia Power Incorporated.

Mr. Edgeworth is President of ALE Energy Inc. and is the former President and Chief Executive Officer of Alliance Pipeline. He is a Director of AltaGas Ltd. and Pembina Pipeline Corporation, and is a Commission Member and Director of the Alberta Securities Commission.

Mr. Edgeworth holds a Bachelor of Applied Science in Geological Engineering and is a graduate of the Queen's Executive Program.

Board/Committee Membership	Attendance	Total %	Public Board Membership During Last Five Years
- Board Member	8 of 8	100%	AltaGas Ltd.
- Audit Committee Member	4 of 4	100%	Pembina Pipelines Corporation
- Management, Resources and Compensation Committee Member	6 of 6	100%	

Securities Held:

Year Ended	Common Shares	DSUs	Value of Shares and DSUs	Status under Share Ownership Guidelines
2009	1,000	14,476	$387,983	Mr. Edgeworth owns shares and DSUs valued at 221% of the requirement under the Guidelines, therefore, Share Ownership Guidelines are met.
2008	1,000	11,922	$286,868	

Christopher G. Huskilson
Age: 52
Wellington, Nova Scotia
Director Since: 2004
Not Independent

Mr. Huskilson has been a Director and the President and Chief Executive Officer of Emera since November 2004. He is also Chair of Bangor Hydro Electric Company, a Director of Nova Scotia Power Incorporated and serves as the Chair or as a Director of a number of other Emera affiliated companies. Mr. Huskilson has held a number of positions within Nova Scotia Power Incorporated and its predecessor, Nova Scotia Power Corporation, since June 1980.

Mr. Huskilson holds a Bachelor of Science in Engineering and a Master of Science in Engineering from the University of New Brunswick.

Board/Committee Membership	Attendance	Total %	Public Board Membership During Last Five Years
- Board Member	8 of 8	100%	ICD Utilities Limited Saint Lucia Electricity Services Limited Algonquin Power and Utilities Corp.

Securities Held:

Year Ended	Common Shares	DSUs	Value of Shares and DSUs	Status under Share Ownership Guidelines
2009	10,129	163,391 (vested and unvested)	$4,350,146	Mr. Huskilson is subject to the Executive Share Ownership Requirements which require that he own shares and/or DSUs valued at 3 times his salary. He exceeds this requirement.
2008	10,114	144,816 (vested and unvested)	$3,439,446	

John T. McLennan
Age: 64
Mahone Bay, Nova Scotia
Director Since: 2005
Independent

Mr. McLennan has been a Director of the Company since April 2005, and has been Chair of the Board of the Company since May 2009. He has been a Director of Nova Scotia Power Incorporated since April 2005 and was the Chair of the Board of Nova Scotia Power Incorporated from May 2006 to May 2009. Mr. McLennan was a member of the Management Resources and Compensation Committee and the Nominating and Corporate Governance Committee from April 2005 to May 2009 when he became Chair of the Board.

Mr. McLennan is the former Vice-Chair and Chief Executive Officer of Allstream Inc. and currently sits on the Board of Jazz Air Holding GP Inc. and Amdocs Ltd.

Mr. McLennan holds a Bachelor of Science, Master of Science and Honorary Doctorate of Science degrees from Clarkson University in New York.

Board/Committee Membership	Attendance	Total %	Public Board Membership During Last Five Years
- Board Chair	7 of 8	87%	Jazz Air Holdings GP Inc. Amdocs Limited

Securities Held:

Year	Common Shares	DSUs	Value of Shares and DSUs	Status under Share Ownership Guidelines
2009	5,000	22,643	$693,006	Mr. McLennan owns shares and DSUs valued at 396% of the requirement under the Guidelines, therefore, Share Ownership Guidelines are met.
2008	5,000	15,336	$451,459	

Donald A. Pether
Age: 62
Dundas, Ontario
Director Since: 2008
Independent

Mr. Pether has been a Director of the Company since November 2008. He has been a member of the Management Resources and Compensation Committee and the Nominating and Corporate Governance Committee since May 2009.

Mr. Pether is the former Chair of the Board and Chief Executive Officer of Dofasco Inc. a Canadian steel producer. Mr. Pether is Chair of the Board of Governors for McMaster University, on the Council of Governors for Hamilton Health Sciences Foundation and the Art Gallery of Hamilton, and a Director of Samuel Manu-Tech Inc.

Mr. Pether has a Bachelor of Science from the University of Alberta.

Board/Committee Membership	Attendance	Total %	Public Board Membership During Last Five Years
- Board Member	8 of 8	100%	Samuel Manu-Tech Inc.
- Management, Resources and Compensation Committee Member	3 of 3	100%	Fording Canadian Coal Trust
- Nominating and Corporate Governance Committee Member	2 of 2	100%	

Securities Held:

Year Ended	Common Shares	DSUs	Value of Shares and DSUs	Status under Share Ownership Guidelines
2009	Nil	1,939	$48,610	Mr. Pether owns shares and DSUs valued at 27% of the requirement under the Guidelines. He became a Board member in November 2008, therefore he has until November 2013 to meet the Share Ownership Guidelines.
2008	N/A	N/A	N/A	

Andrea S. Rosen
Age: 55
Toronto, Ontario
Director Since: 2007
Independent

Ms. Rosen has been a Director of the Company since January 2007 and has been a member of Emera's Audit Committee since May 2007. She was appointed Audit Committee Chair in April 2008.

Ms. Rosen is the former Vice-Chair, TD Bank Financial Group and President, TD Canada Trust. Ms. Rosen is also a Director of Alberta Investment Management Corporation and Hiscox Ltd.

Ms. Rosen received her joint LL.B and M.B.A. from Osgoode Hall Law School, York University.

Board/Committee Membership	Attendance	Total %	Public Board Membership During Last Five Years
- Board Member - Audit Committee Chair	8 of 8 4 of 4	100% 100%	Hiscox Ltd.

Securities Held:

Year Ended	Common Shares	DSUs	Value of Shares and DSUs	Status under Share Ownership Guidelines
2009	Nil	9,628	$241,373	Ms. Rosen owns shares and DSUs valued at 137% of the requirement under the Guidelines, therefore Share Ownership Guidelines are met.
2008	Nil	5,974	$132,623	

M. Jacqueline Sheppard
Age: 54
Calgary, Alberta
Director Since: 2009
Independent

Ms. Sheppard has been a Director of the Company since February 2009. She has been a member of the Audit Committee and the Management Resources and Compensation Committee since May 2009.

Ms. Sheppard is a Director of NWest Energy Inc., a Canadian junior oil and gas company and is the former Executive Vice-President, Corporate and Legal and Corporate Secretary for Talisman Energy Inc., an international oil and gas company based in Calgary, Alberta, Canada.

Ms. Sheppard is a Rhodes Scholar, having received an Honours Jurisprudence, Bachelor of Arts and Masters of Arts from Oxford University. She received her law degree (Honours) from McGill University.

Board/Committee Membership	Attendance	Total %	Public Board Membership During Last Five Years
- Board Member - Audit Committee Member - Management, Resources and Compensation Committee Member	8 of 8 2 of 2 2 of 3	100% 100% 67%	NWest Energy Inc.

Securities Held:

Year Ended	Common Shares	DSUs	Value of Shares and DSUs	Status under Share Ownership Guidelines
2009	Nil	2,010	$50,390	Ms. Sheppard owns shares and DSUs valued at 28% of the requirement under the Guidelines. She became a Board member in February 2009, therefore she has until February 2014 to meet the Share Ownership Guidelines.
2008	N/A	N/A	N/A	

Other Publicly–Traded Directorships

Emera Director nominees currently serve as Directors on other publicly-traded companies, as set out in the table below.

Emera Director Nominee	Other Publicly-Traded Directorships
Robert S. Briggs	None
Thomas W. Buchanan	Provident Energy Trust Hawk Exploration Ltd.
Gail Cook-Bennett	Manulife Financial Corporation
George A. Caines	None
Allan L. Edgeworth	AltaGas Ltd. Pembina Pipeline Corporation
Christopher G. Huskilson	ICD Utilities Limited Saint Lucia Electricity Services Ltd. Algonquin Power and Utilities Corp.
John T. McLennan	Jazz Air Holdings GP Inc. Amdocs Ltd.
Donald A. Pether	Samuel Manu-Tech Inc.
Andrea S. Rosen	Hiscox Ltd.
M. Jacqueline Sheppard	NWest Energy Inc.

Compensation of Directors

The Nominating and Corporate Governance Committee is responsible for reviewing Directors' compensation. As part of its review, the Committee considers compensation practices of Canadian publicly-traded companies that are similar in operation and size to Emera and ensures that Directors are appropriately compensated for the responsibilities and risks involved in being a Director.

Listed below are the annual compensation rates for independent Directors during 2009. These rates were first effective January 1, 2008. These rates are not applicable to Mr. Huskilson as the only management Director, nor to Mr. G.A. Caines as Chair of NSPI.

Annual Chair's Retainer: (This is an all-inclusive fee. The Chair of the Board receives no meeting fees or any other retainers)	$160,000
Annual Director Retainer:	$ 35,000
In-Person Meeting Fee:	$ 1,750
Telephone Meeting Fee:	$ 1,250
Travel Fee: (if one-way travel is 5 hours or more)	$ 1,750
Travel Fee: (if one-way travel is at least 3 hours but less than 5 hours)	$ 875
Annual Audit Committee Chair Retainer:	$ 15,000
Annual Audit Committee Member Retainer:	$ 5,000
Annual Management Resources and Compensation Committee Chair Retainer:	$ 12,000
Annual Management Resources and Compensation Committee Member Retainer:	$ 3,000
Annual Nominating and Corporate Governance Committee Chair Retainer:	$ 5,000
Annual Nominating and Corporate Governance Committee Member Retainer:	$ 3,000

Effective January 1, 2010 certain annual compensation rates for independent Directors increased. For details about these new rates please see "Director Compensation" in the section of this Circular entitled "Statement of Corporate Governance Practices".

Total Director Compensation

The following table sets out the total gross compensation earned by all Directors who served on Emera's Board during 2009 for attendance at Board and Committee meetings for which a Director attended as a member or guest, briefing meetings, education sessions, and travel fees.

Director (1) (2)	Fees Earned in 2009 (3) ($)	Share Based Awards(4) ($)	All Other Compensation ($)	Total ($)
R.S. Briggs	76,750	0	N/A	76,750
T.W. Buchanan (5)	54,274	51,534	N/A	54,274
G.A. Caines (6)	N/A	18,386	103,625	103,625
G. Cook-Bennett	61,875	83,823	N/A	61,875
A.L. Edgeworth	85,750	64,042	N/A	85,750
J.T. McLennan (7)	105,205	183,206	37,973	143,178
D. Oland	121,979	6,542	N/A	121,979
E. Parr-Johnston	79,750	59,380	N/A	79,750
D. A. Pether	66,570	48,611	N/A	66,570
A.S. Rosen	73,250	91,601	N/A	73,250
M.J. Sheppard(8)	69,387	50,398	N/A	69,387

Notes:

(1) During 2009, the Company did not offer share-based awards (except Directors did have the ability to elect to receive some or all of their cash compensation in the form of DSUs), option-based awards, non-equity incentive plan participation, or participation in a Company pension plan to its Directors.

(2) Mr. Huskilson is not included in the above table as his compensation for service as Emera's President and Chief Executive Officer is disclosed in the Statement of Executive Compensation. He does not receive any additional compensation for his services as a Director of Emera.

(3) All Directors are paid in Canadian dollars.

(4) This column shows the value obtained when the number of DSUs awarded to each Director in 2009 in lieu of cash compensation, pursuant to elections made by such Director, plus dividends earned on the DSUs in the form of additional DSUs is multiplied by the December 31, 2009 Emera share closing price of $25.07.

(5) Mr. Buchanan was appointed to the Board of Directors effective May 6, 2009.

(6) Mr. Caines was appointed as Chair of NSPI May 6, 2009 and is only paid by NSPI for his services as NSPI's Chair. The amount reflected above represents his NSPI compensation as an NSPI Director from January to May 2009 and his NSPI compensation as NSPI's Chair of the Board from May 2009 to December 2009. Mr. Caines does not receive any additional compensation for his services as a Director of Emera.

(7) Mr. McLennan was appointed Chair of Emera May 6, 2009. The fee reflected above represents his prorated Chair fee for the period May 2009 to December 2009 paid by Emera. The amount reflected in "All Other Compensation" reflects his compensation paid by NSPI as Chair of NSPI from January 2009 to May 2009.

(8) Ms. Sheppard was appointed to the Board of Directors effective February 13, 2009.

All independent Directors are reimbursed for expenses incurred for attendance at Board, Committee, and Shareholders' Meetings and when on Company business. They are also eligible to participate in certain group health benefits which are available to employees and, if they choose to participate, are required to contribute to the premium costs of such benefits in the same fashion as employees.

Directors Share Ownership Guidelines

The Directors are subject to share ownership guidelines that require them to own common shares and/or deferred share units with a value of not less than $175,000 within a specified timeframe. For more information about the Director Share Ownership Guidelines see the heading "Director Share Ownership Guidelines" in the section of this Circular entitled "Statement of Corporate Governance Practice".

Directors Deferred Share Unit Plan

Under the Directors deferred share unit plan (the "Plan"), independent Directors may elect to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each quarterly payment, the applicable amount is converted to DSUs.

A DSU is a bookkeeping entry that has a value based upon the value of one Emera common share. When a dividend is paid on Emera's common shares, the Director's DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption. DSUs are not shares, cannot be converted to shares, and do not carry voting rights.

Effective January 1, 2010, independent Directors' began receiving a portion of their annual retainer in grants of DSUs. See "Director Compensation" in the Statement of Corporate Governance Practices in this Circular for more information about Director Compensation.

Independent Directors are not entitled to participate in any other compensation plan of the Company or in the Employee Common Share Purchase Plan.

Committees of the Board of Directors

The Board of Directors has three standing Committees to assist it in carrying out its duties. The Committees are:

- Audit;
- Management Resources and Compensation; and
- Nominating and Corporate Governance.

For further information on the Committees, see "Statement of Corporate Governance Practices".

Director Meeting Attendance

During 2009, the Board or its Committees met on 22 occasions. Listed in the following table is the number of Board and Committee meetings attended by each Director in 2009. It does not include attendance at Committee meetings as a guest, briefing meetings, or education sessions. In the table below, references to the Management Resources and Compensation Committee are referred to as “MRCC”, and references to the Nominating and Corporate Governance Committee are referred to as “NCGC”.

Director	Number of Meetings Attended		Percentage of Meetings Attended	Comments
Robert S. Briggs	Board:	8 of 8	100%	
	Shareholders Meeting:	1 of 1	100%	
	Audit Committee:	4 of 4	100%	
	MRCC:	N/A	N/A	
	NCGC:	N/A	N/A	
Thomas W. Buchanan (1)	Board:	5 of 5	100%	
	Shareholders Meeting:	N/A	N/A	
	Audit Committee:	2 of 2	100%	
	MRCC:	N/A	N/A	
	NCGC:	2 of 2	100%	
George A. Caines (2)	Board:	2 of 2	100%	
	Shareholders Meeting:	N/A	N/A	
	Audit Committee:	N/A	N/A	
	MRCC:	N/A	N/A	
	NCGC:	N/A	N/A	
Gail Cook-Bennett	Board:	7 of 8	87%	
	Shareholders Meeting:	0 of 1	0%	
	Audit Committee:	N/A	N/A	
	MRCC:	N/A	N/A	
	NCGC:	3 of 3	100%	
Allan L. Edgeworth	Board:	8 of 8	100%	
	Shareholders Meeting:	1 of 1	100%	
	Audit Committee:	4 of 4	100%	
	MRCC:	6 of 6	100%	
	NCGC:	N/A	N/A	
Christopher G. Huskilson (3)	Board:	8 of 8	100%	
	Shareholders Meeting:	1 of 1	100%	
	Audit Committee:	N/A	N/A	
	MRCC:	N/A	N/A	
	NCGC:	N/A	N/A	
John T. McLennan (4)	Board:	7 of 8	87%	
	Shareholders Meeting:	1 of 1	100%	
	Audit Committee:	N/A	N/A	
	MRCC:	3 of 3	100%	
	NCGC:	1 of 1	100%	
Derek Oland (5)	Board:	8 of 8	100%	Mr. Oland advised of his intention to retire from the Board and will not stand for nomination at the 2010 shareholders’ meeting.
	Shareholders Meeting:	1 of 1	100%	
	Audit Committee:	N/A	N/A	
	MRCC:	2 of 3	67%	
	NCGC:	N/A	N/A	
Elizabeth Parr-Johnston	Board:	8 of 8	100%	Dr. Parr-Johnston advised of her intention to retire from the Board and will not stand for nomination at the 2010 shareholders’ meeting.
	Shareholders Meeting:	1 of 1	100%	
	Audit Committee:	N/A	N/A	
	MRCC:	6 of 6	100%	
	NCGC:	3 of 3	100%	

Director	Number of Meetings Attended		Percentage of Meetings Attended	Comments
Donald A. Pether (6)	Board:	8 of 8	100%	
	Shareholders Meeting:	1 of 1	100%	
	Audit Committee:	N/A	N/A	
	MRCC:	3 of 3	100%	
	NCGC:	2 of 2	100%	
Andrea S. Rosen	Board:	8 of 8	100%	
	Shareholders Meeting:	1 of 1	100%	
	Audit Committee:	4 of 4	100%	
	MRCC:	N/A	N/A	
	NCGC:	N/A	N/A	
M. Jacqueline Sheppard (7)	Board:	8 of 8	100%	
	Shareholders Meeting:	1 of 1	100%	
	Audit Committee:	2 of 2	100%	
	MRCC:	2 of 3	67%	
	NCGC:	N/A	N/A	

Notes:

(1) Mr. Buchanan was appointed a Director, an Audit Committee member, and a Nominating and Corporate Governance Committee member on May 6, 2009.

(2) Mr. Caines was appointed a Director on September 25, 2009.

(3) Mr. Huskilson is not a member of any Committee, however, as President and Chief Executive Officer he attends Committee meetings in a non-voting capacity. He did not participate in any portion of Board and/or Committee meetings that dealt with his role or performance.

(4) Mr. McLennan was appointed Chair of the Board on May 6, 2009. Prior to his Chair appointment, Mr. McLennan was a member of the Management Resources and Compensation Committee and a member of the Nominating and Corporate Governance Committee. His attendance as a member of these Committees is noted above. As Chair of the Board Mr. McLennan is not a member of any of Emera's Committees; however, he attends Committee meetings in a non-voting capacity and attended an additional 8 of 8 Committee meetings.

(5) Mr. Oland was Chairman of the Board until May 6, 2009. As Chairman of the Board Mr. Oland was not a member of any of Emera's Committees; however, he attended Committee meetings in a non-voting capacity and attended 5 of 5 Committee meetings. On May 6, 2009 Mr. Oland was appointed a member of the Management Resources and Compensation Committee and his attendance as a Committee member is noted above.

(6) Mr. Pether was appointed to the Management Resources and Compensation Committee and the Nominating and Corporate Governance Committee on May 6, 2009.

(7) Ms. Sheppard was appointed to the Audit Committee and the Management Resources and Compensation Committee on May 6, 2009.

Certain Proceedings

To the knowledge of the Company, none of the proposed nominees for election as Directors of the Company:

(a) are, as at the date of this Circular, or have been, within ten years before the date of this Circular, a Director, Chief Executive Officer or Chief Financial Officer of any company that:

(i) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days (an "Order") that was issued while the proposed nominee was acting in the capacity as Director, chief executive officer or chief financial officer; or

(ii) was subject to an Order that was issued after the proposed nominee ceased to be a Director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as Director, chief executive officer of chief financial officer,

(b) are, as at the date of this Circular, or have been within ten years before the date of this Circular, a Director or executive officer of a company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangements or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(c) have, within the ten years before the date of this Circular, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the proposed nominee, except for:

John T. McLennan was the Chief Executive Officer of AT&T Canada when AT&T Canada filed for protection under the *Companies' Creditors Arrangement Act* on October 15, 2002.

Statement of Executive Compensation

Management Resources and Compensation Committee

The Management Resources and Compensation Committee of the Board of Directors (the "MRCC") determines the compensation for Emera's executive officers, and reviews, approves and oversees the administration of all of the Company's executive compensation plans and programs. The MRCC currently consists of Elizabeth Parr-Johnston (Chair), Allan L. Edgeworth, Derek Oland, Donald A. Pether, and M. Jacqueline Sheppard.

All members of the MRCC are independent Directors meaning none have been officers or employees of the Company or its subsidiaries. They do not have any relationship which resulted in indebtedness to the Company or its subsidiaries, nor any interest in transactions which have or would materially affect the Company or its subsidiaries.

The Board has assigned responsibility to the MRCC for reviewing overall compensation policies and for reviewing and recommending compensation for senior management of the Company.

The MRCC also has responsibility for ensuring that, on an annual basis, the performance of the President and Chief Executive Officer is assessed and for ensuring that the Company adequately carries out succession planning. On an annual basis, the Company's President and Chief Executive Officer provides a list of potential successors for his position to the MRCC. This activity also includes identifying internal successors for each of the Named Executive Officers and senior management throughout the Company and its affiliates. The Board of Directors reviews the recommendations of the MRCC and gives approval on compensation matters for senior management of the Company as well as on policy changes related to compensation.

For the purposes of compensation disclosure, the individuals listed in the 2009 "Summary Compensation Table" are the President and Chief Executive Officer, the Vice-President and Chief Financial Officer and the next three most highly compensated executive officers of the Company, or its affiliated companies, as defined by Canadian securities legislation (the "Named Executive Officers").

Compensation Advisors

The MRCC retains the services of independent advisors as needed in order to assist it in discharging its duties.

Since 2007, the MRCC has engaged Hugessen Consulting Inc. ("Hugessen") as its principal advisor to provide independent advice, compensation analysis and other information for compensation recommendations. Hugessen provides advice on the competitiveness and appropriateness of compensation practices and comparator groups for Emera and its affiliates. In addition, Hugessen provides advice to the MRCC on policy recommendations by management, and also reviews and provides commentary on the Company's Statement of Executive Compensation. In 2009, Hugessen was also retained by the Company's Nominating and Corporate Governance Committee to provide independent advice and compensation analysis regarding Director's compensation.

The MRCC has adopted a number of practices with regard to its executive compensation advisor:

- The MRCC annually reviews the advisor's performance and fees;
- With input from Company management and the advisor, the MRCC annually, or on an as-needed basis, determines the specific work to be undertaken by the advisor for the MRCC and the fees associated with this work;
- All services provided by the MRCC's advisor beyond its role in supporting the requirements of the MRCC require written pre-approval by the MRCC Chair outlining the scope of work and related fees. The

MRCC does not approve any such work that, in its view, could compromise the advisor's independence in serving the MRCC;
- The work done and the fees paid by Emera to compensation advisors are disclosed annually in this Circular.

In addition to the MRCC's compensation advisor in 2009, management engaged the services of Towers Watson (formerly Towers Perrin) and Morneau Sobeco.

In 2009, Towers Watson was engaged to assist in compiling market information on senior management compensation for NSPI relating to base salary, and short-term and long-term incentives. Towers Watson's scope of services included competitive reviews of executive compensation levels and information on industry trends.

Also in 2009, Morneau Sobeco completed actuarial analysis on Emera's long-term incentive plan and provided current data on the Executive Pension Plan.

The MRCC reviews information and recommendations provided by Hugessen, Towers Watson and Morneau Sobeco, as it considers its decisions relevant to the objectives of the compensation program.

The table below summarizes the fees paid to all external compensation advisors in 2009:

Advisor	All MRCC Work	All Other Work
Hugessen Consulting Inc.	$30,728	$31,600[1]
Towers Watson	Nil	$12,781
Morneau Sobeco	Nil	$47,464

(1) Hugessen Consulting Inc. was retained by the Nominating and Corporate Governance committee in 2009 to review Director's compensation

Compensation Discussion and Analysis

Objective of Compensation Program

The purpose of Emera's executive compensation program is to reward Emera's executives for sustained increases in shareholder value; to attract, retain and motivate highly qualified and high-performing executives; and to align the interests of executives with the interests of Emera's shareholders.

Compensation Program Design

Emera's compensation program is designed to be competitive in relevant labour markets, include both short-term and long-term performance goals and link compensation to the Company's performance as measured by specific financial results.

Market Competitiveness – Emera's executive compensation program is designed to provide total target compensation at the median or 50^{th} percentile of compensation paid by similar industries and similarly-sized companies. "Total Target Compensation" for senior management, including the Named Executive Officers, for these purposes, is comprised of:

- base salary,
- target annual incentive, and
- target long-term incentives linked to total shareholder value.

Pay for Performance – Emera's executive compensation philosophy is that a significant proportion of executive compensation must be at risk. The at risk components depend on achieving Company, business unit and individual performance objectives. These objectives are set forth in scorecards that establish agreed upon objectives that are measurable and incent performance by each executive that is appropriate to the position and, if achieved, will contribute value to the Company or its affiliates in the form of financial results, value to customers, value to assets or value to other employees with the organization ("Scorecards"). Executives' performance against each Scorecard is measured and rated. The Executive must have achieved a threshold level of performance for any payment against a particular objective, failing which there is no payment against such objective. Accordingly, incentive compensation plans and programs are designed to pay larger amounts for superior performance and smaller amounts if target performance is not achieved.

Generally, the higher the level of the responsibility, the greater the portion of Total Target Compensation that is variable and at risk.

The compensation plan designed for 2009 resulted in the target annual incentive for the Named Executive Officers being comprised of between 17 percent to 31 percent of total pay at risk and the target long-term incentives (stock options and restricted share units (RSUs)) being between 20 percent to 46 percent of total pay at risk. The following table shows the percentage weighting of each component of the Total Target Compensation for the Named Executive Officers. At least 45 percent of the Total Target Compensation is at risk for each of the Named Executive Officers.

Name	Base Salary (%)	Annual Incentive at Target (%)	Long-Term Incentive at Target (%)	Total Pay at Risk (%)
C.G. Huskilson	34%	20%	46%	66%
N.G. Tower	45%	23%	32%	55%
R.R. Bennett	50%	20%	30%	50%
R.J.S. Hanf	55%	17%	28%	45%
W.D. O'Connor	49%	31%	20%	51%

Management considers many factors when developing annual incentive and long term incentive design, including; current compensation trends; plan costs at payout; expected value to be delivered to participants; maximum payout values and causal analysis of minimum, target and maximum payouts.

Both annual incentive and long-term incentive plan designs are modeled using historical and prospective performance scenarios. This stress testing provides the MRCC with reasonable assurance that the plan payouts will be appropriate and aligned with shareholder and Company objectives. Analysis is also done every year to determine how actual payouts compare to expected payouts and whether the plan components require any changes.

The MRCC has, in its sole and absolute discretion, the ability to facilitate if required, changes to compensation incentive design results. The MRCC is able to, and has in the past, exercised its discretion to change compensation payouts versus company results.

Benchmarking Data

Emera management engages the services of a compensation consultant (Towers Watson) to compile market information on senior management compensation, including the Named Executive Officers, relating to base salary, short-term and long-term incentives. A complete benchmarking review takes place on an annual basis for Nova Scotia Power Inc. and every second year for Emera Inc. This scope of services includes competitive market reviews of senior executive compensation levels.

The MRCC undertakes periodic reviews of compensation design and total compensation opportunities for the Named Executive Officers to ensure that the programs are current and that they achieve fair comparisons for particular roles, recognizing varying responsibility and scope of executive positions within Emera and its affiliates.

The MRCC reviews compensation data based on a comparator group of companies, primarily regulated utilities and other energy industry enterprises that approximate the size and scope of Emera. While the intention is to use a consistent list of comparators from year to year, the comparators used for compensation review are subject to some change each year due to (a) the availability of relevant pay data, (b) mergers and acquisitions, and (c) the relevance of new comparators based on updated financial metrics.

Based on the benchmark data, the President and Chief Executive Officer recommends Total Target Compensation for each Named Executive Officer to the MRCC, excluding himself. With respect to the President and Chief Executive Officer, the MRCC reviews benchmark data and other information regarding industry trends for positions of similar scope. Following this process, the MRCC makes recommendations for Total Target Compensation for all of the Named Executive Officers to the Board of Directors.

Two sources are used to gather market information about executive compensation and establish benchmark data for Emera and its affiliates:

(1) **Publicly-Disclosed Compensation Data (Applicable to Named Executive Officers only)** – For purposes of reviewing the 2009 compensation of the President and Chief Executive Officer, Emera Inc. and the Chief Financial Officer, Emera Inc., in the fall of 2008, Hugessen benchmarked against similar positions of comparable organizations using publicly-disclosed compensation data.

The following publicly-traded organizations were analyzed as the primary comparator group for the purposes of the compensation benchmarking described above. This comparator group consisted of the same companies used to benchmark compensation in 2008, based on 2007 benchmarking carried out by Hugessen, with the exception that Canadian Hydro Developers and TransAlta were removed because of updated financial metrics or merger or acquisition activity as discussed above.

<u>S&P / TSX Utilities Sector Index:</u>

ATCO Ltd.
Algonquin Power Income Fund
Canadian Hydro Developers Inc.
Canadian Utilities Ltd.
EPCOR Power L.P
Fortis Inc.
Northland Power Income Fund
Energy Savings Income Fund
TransAlta Corp.

The following publicly-traded organizations were also analyzed for the purposes of Emera's President and CEO and CFO compensation benchmarking as described above. The rationale for incorporating the energy industry includes a view that senior talent can migrate between similar organizations (ie. industry, scale, complexity) and the fact that Emera's strategic objectives include expansion into various energy-related sectors.

The comparator group below consisted of the same companies used to benchmark compensation in 2008, based on 2007 benchmarking carried out by Hugessen, with the exception that Canetic Resouces Trust was removed and ShawCor and Ensign Energy Services were added because of updated financial metrics or merger or acquisition activity as discussed above.

<u>Energy Industry Comparables:</u>

Pengrowth Energy Trust
Ensign Energy Services Inc.
Precision Drilling Trust
Inter Pipeline Fund
Enbridge Income Fund
Fort Chicago Energy Partners LP
Pembina Pipeline Income Fund
ShawCor Limited

(2) **Survey Data** – In the fall of 2008, Towers Watson conducted a review of competitive compensation levels for Named Executive Officers and other senior management. For this review, data was sourced from Towers Watson's Compensation Data Bank. The primary comparator group was comprised of a select sample of energy organizations, including regulated utilities, where data was available.

The comparator group was comprised of the following organizations:

Alberta Electric System Operator
Alliance Pipeline
AltaLink Management Ltd.
ATCO Ltd. and Canadian Utilities Ltd.
Atomic Energy of Canada Ltd.
British Columbia Hydro and Power Authority
Bruce Power LP
Duke Energy/Spectra Energy
Enbridge Gas Distribution Inc.
Enbridge Inc.
Enmax Corporation
EPCOR Power LP
FortisAlberta Inc.
Hydro-One
Hydro-Quebec
Imperial Oil Ltd.
Inter Pipeline Fund
Kinder Morgan
New Brunswick Power Corporation
Newfoundland & Labrador Hydro Electric
Ontario Power Generation Inc.
SaskEnergy
SaskPower
Shell Canada Ltd.
TransAlta Corporation
TransCanada Pipelines Ltd.

<u>Compensation Process</u>

Benchmark data and other information regarding industry trends for positions of similar scope and responsibility are used to establish a base salary range for each position and a range for annual incentive and long-term incentive compensation for each position.

On an annual basis the President and Chief Executive Officer conducts performance assessments for each Named Executive Officer which can influence the annual salary adjustment recommendation for a Named Executive Officer.

Elements of Compensation

Base Salary

Base salaries for each Named Executive Officer are benchmarked against the median of the salaries paid for positions with similar responsibilities by comparator companies. The base salary for each Named Executive Officer is reviewed annually and reflects the degree of special skill and knowledge required for the position and the performance and contribution of the individual. Base salary is designed to be a component of Total Target Compensation and provides a threshold level of cash compensation for job performance that is not at risk in the way that annual incentive compensation would be.

Annual Incentive

Annual incentive compensation is intended to link a portion of an employee's compensation to the achievement of predetermined levels of performance in support of corporate and business unit objectives ("Annual Incentive"). Those objectives are set forth in the Executive's Scorecard and designed to focus attention on short term goals that are intended to deliver value to customers and contribute to increased shareholder value in the longer term. Target payouts under the Scorecards are generally set as a percentage of salary and are benchmarked against the median for positions with similar responsibilities in comparator companies. Emera has adopted the Scorecard approach to translate corporate strategies into measurable incentive plan goals.

On the recommendation of the MRCC, the Board of Directors of Emera approved scorecards setting forth objectives and related threshold, target and stretch performance levels to be achieved in 2009 on which the Annual Incentive for the majority of Named Executive Officers would be based. Payouts can range from 0% to 200% of target. Four of the five Named Executive Officers have their Annual Incentive calculated based on results achieved through Scorecard results. The Annual Incentive for Mr. W.D. O'Connor, however, is based on the year-end financial results of Emera Energy Inc. and based on an assessment of achievement of objectives and progress on new business development, as well as asset management and human resource development.

2009 Emera Corporate Scorecard

The Scorecard for Emera ("Emera Corporate Scorecard") is developed and recommended by management for approval by the MRCC and the Emera Board of Directors at the beginning of each year. It is used to determine the Annual Incentive for Emera's President and Chief Executive Officer and Emera's Chief Financial Officer.

Objectives on the 2009 Emera Corporate Scorecard included a 90 percent weighting for strengthening the financial position of the Company through generating growth as measured by:

- earnings per share; and
- cash flow per share

The corporate objective of maintaining and enhancing employee commitment and wellness received a 10 percent weighting on the Scorecard.

The Emera Corporate Scorecard objectives are based on the Company's Business Plan for the year and establish threshold, target, and stretch performance standards for each objective.

The MRCC determined that the President and Chief Executive Officer, Emera and the Chief Financial Officer, Emera achieved 172 percent of target performance pursuant to the 2009 Corporate Scorecard. The following table shows the elements of the Emera Corporate Scorecard for 2009.

Emera Inc. Corporate Objective	Weighting	Target	Actual Result	Percentage Payout[1]
Earnings Per Share [2]	60%	$1.42	$1.55 [2]	120%
Cash Flow Per Share	30%	$2.90	$2.94	42%
Employee Commitment and Wellness as Measured by the Annual Employee Survey[3]	10%	Action plans implemented that would improve Employee Commitment and participation in Wellness screenings	Target	10%
	100%			Total = 172%

Notes:

(1) Percentage payouts, below or above target for financial measures, will be prorated on a scale between each level of performance.

(2) Earnings per share for the Company were $1.55, or $1.56 excluding mark-to-market adjustments for 2009. The mark-to-market accounting adjustment arises as a result of a contract between Brookfield Power and Bear Swamp Power Company (of which each of Emera and Brookfield holds a 50% interest). The contract fixes the price of power between Brookfield and Bear Swamp Power Company but it does not fall within the strict hedge accounting rules and therefore gets mark-to-market treatment. In 2009, as in prior years, earnings per share excludes the mark-to-market adjustment for incentive calculation purposes.

(3) Based on completing these objectives the Company would expect a statistically significant increase on the annual employee survey results relating to the areas.

The table below shows Emera's trending for the period 2005 to 2009 of earnings per share and cash flow per share as of December 31.

	2005 ($)	2006 ($)	2007 ($)	2008 ($)	2009 ($)
Earnings Per Share[1]	1.11	1.14	1.28	1.33	1.55
Cash Flow Per Share	2.40	2.83	3.28	2.84	2.94

Notes:

(1) Earnings Per Share numbers reflect results excluding mark-to-market adjustments.

Scorecard performance has paid out an average 118% of target over the last five years. Earnings Per Share performance has trended upwards over the same period, meeting or exceeding the corporate targets since 2006.

2009 Nova Scotia Power Incorporated ("NSPI") Corporate Scorecard

The NSPI Corporate Scorecard is developed and recommended by NSPI management for approval by the NSPI Management Resources, Compensation, Environment, Safety & Security Committee ("MRCESSC") and the NSPI Board of Directors at the beginning of each year, and receives final approval from the MRCC. It is used to determine the Annual Incentive for NSPI's President and Chief Executive Officer, one of the Named Executive Officers in 2009.

Objectives on the 2009 NSPI Corporate Scorecard included a 40 percent weighting for strengthening the financial position of NSPI by generating growth as measured by financial earnings and cash from operations. Reputation with the customer received a 30 percent weighting. Asset management was weighted at 15 percent, People and Safety made up the balance at 7.5 percent each respectively.

On the recommendation of the NSPI MRCESSC, the MRCC determined that the Named Executive Officer of NSPI achieved an aggregate of 134.8 percent of target on all the objectives measured in the NSPI Corporate Scorecard in 2009. The following table shows the objectives of the NSPI Corporate Scorecard for 2009.

Nova Scotia Power Inc. Corporate Objective	Weighting	Target	Actual Result	Percentage Payout
Financial - Earnings (1)	30%	$104 million	$111 million	60.0
Financial - Cash From Operations (1)	10%	$195 million	$250 million	20.0
Customer - Service Reliability (1) (SAIFI x SAIDI)	10%	11.5	11.6	9.8
Customer - Customer Satisfaction Survey	20%	Customer satisfaction at least 77%	67%	0.0
Asset Management - Progress on Greener Cleaner Strategy	15%	Deliver on an integrated resource plan that establishes the best assets to improve efficiency and meet environmental standards and perception of environmental performance and reputation improves	Stretch	30.0
People - Attract and Retain Talent	7.5%	Corporate Succession plan developed at all levels and 70% of employees participated in a wellness activity	Target	7.5
Safety	7.5%	LTF is less than "Best ever NSPI performance"	Threshold	7.5
	100.0%		**Total**	**134.8%**

Notes:
(1) Percentage payouts, below or above target, will be prorated on a scale between each level of performance.

2009 Bangor Hydro Electric Company ("BHE") Corporate Scorecard

The BHE Corporate Scorecard is developed and recommended by a subcommittee of BHE management and a Board member for approval by the BHE Board of Directors at the beginning of each year, and receives final approval from the MRCC. It is used to determine the Annual Incentive for BHE's President and Chief Executive Officer, one of the Named Executive Officers in 2009.

Objectives on the BHE Corporate Scorecard included specific financial targets of earnings per share and net income (55 percent), customer satisfaction (20 percent), asset management (10 percent), safety performance (7.5 percent) and people/workplace excellence (7.5 percent).

On the recommendation of the BHE Board of Directors, the MRCC determined that the Named Executive Officer of BHE achieved an aggregate of 131.25 percent of target on all the objectives measured in the BHE Corporate Scorecard in 2009. The following table shows the objectives of the BHE Corporate Scorecard for 2009.

Bangor Hydro Electric Company Corporate Objective	Weighting	Target	Actual Result	Percentage Payout
Financial - Earnings Per Share(1)	20%	$1.42	$1.55	40.0
Financial – Net Income (1)	35%	$24.7 million	$25.2 million	52.5
Customer - Customer Satisfaction Survey	20%	Increase favorable movement on customer satisfaction index by 4 or more percentage points	Threshold	10.0
Asset Management - Strategic Plan process	10%	Complete 80% of the 2009 strategic plan items relating to capital planning, FERC and the environment	Target	10.0
Safety – Performance and Reporting	7.5%	Year End Injury Rate of 4.6	5.4	3.75
People – Workplace Excellence	7.5%	Establish Company wide Wellness Program and achieve employee participation rate of at least 25%	Stretch	15.0
	100.0%		**Total**	**131.25%**

Notes:
(1) Percentage payouts, below or above target, will be prorated on a scale between each level of performance.

2009 Emera Energy Incorporated Annual Incentive

Mr. W.D. O'Connor participates in Emera Energy Incorporated's annual incentive plan. Under the plan, Mr. O'Connor is allocated an annual incentive determined by the MRCC based on the year-end financial results of Emera Energy Inc. and based on an assessment of achievement of objectives, including progress on new business development, as well as asset management and human resource development.

Long-Term Incentive

There are two components of long-term incentive compensation for the Named Executive Officers; namely, the Restricted Share Unit Plan (the "RSU Plan") and the Senior Management Stock Option Plan (the "Stock Option Plan").

The RSU Plan makes up 50 percent of the target long-term incentive compensatory value for Mr. C.G. Huskilson and 75 percent of the target long-term incentive compensatory value for all other Named Executive Officers. The Stock Option Plan makes up 50 percent of the target long-term compensatory value for Mr. C.G. Huskilson and 25 percent of the target long-term incentive compensatory value for all other Named Executive Officers.

The number of restricted share units ("RSUs") and stock options granted to the Named Executive Officers is determined based on competitive benchmarking data and the level of responsibility within the Company; generally, the level of grant increases with the level of responsibility. The MRCC is responsible for granting RSUs and stock options.

The RSUs and the stock options increase in value in proportion to the increase in the market price of Emera's common shares over the term of a particular grant.

More details about the RSU Plan and the Stock Option Plan are set forth below.

The options granted to senior management are determined as a percentage of base salary in each year. The value of stock option grants are based on the Black-Scholes valuation methodology. The Black-Scholes value was determined to be equal to 11.4 percent of the closing share price of $21.99 as of February 12, 2009.

Previous grants of stock options and RSUs to senior management are taken into account when recommending new grants by considering a three year history on total compensation, which also includes long-term incentive (stock options and RSUs) and is reviewed for Named Executive Officers each year to ensure reasonable progression within the market.

Restricted Share Unit Plan

Emera has adopted a Restricted Share Unit Plan ("RSU Plan") which is designed to retain and incent employee participants by allowing senior management and executive to participate in the long-term success of the Company.

The RSU Plan provides for the establishment of performance based requirements by the MRCC. Under the RSU Plan, participants receive annual grants of Restricted Share Units ("RSUs"). The RSU Plan pays monetary rewards based on a combination of financial measurements over a three-year performance period as established by the MRCC pursuant to the RSU Plan. For the 2009 grants, the MRCC established the following as the performance factors:

(a) Emera's total stock return relative to the total return of S&P/TSX Capped Utilities Index; and
(b) the average growth in Emera earnings per share.

In 2009 the initial grant value of an RSU was based on the average 50 trading-day share price on December 31, 2008 ($21.41) multiplied by a value ratio factor of 1.111. This RSU value ratio is a discounting factor to offset the additional value expected to be received through dividend reinvestment over the three-year period of the grant. RSUs vest and are paid out at the end of a three-year performance period.

The number of RSUs granted to each employee participant is intended to pay 100 percent of the RSU target based incentive at the end of the three-year performance period if Emera achieves its financial objectives measured by the performance factors.

Performance Factor 1

Performance factor 1 is based on Emera's average three-year total stock return in excess of the average three year return of the S&P/TSX Capped Utilities Total Return Index.

The table below shows the Company's total stock return performance relative to the return of the S&P/TSX Capped Utilities Index and, on the right, the corresponding performance factor value under the RSU Plan.

Relative Annual Return to S&P/TSX Capped Utilities Total Return Index	Performance Factor
Less than -5%	0.00
-5%	0.50
0%	1.00
5% or more	1.50

Performance Factor 2

Performance factor 2 is based on Emera's average annual growth in earnings per share. Dividends must be maintained at or higher than the December 31, 2008 levels. If dividends are reduced, Factor 2 will be deemed to be 0 regardless of the earnings per share growth.

The table below shows the Company's average three-year earnings per share growth and, on the right, the corresponding performance factor value under the RSU Plan.

Emera Average Three-Year Earnings per Share Growth (CAGR)*	Performance Factor
Less than 4%	0.00
4%	0.50
5%	1.00
7% or more	1.50

*Compound Annual Growth Rate

The value of each performance factor will be interpolated on the basis of the actual results. In addition, all annual averages over the three-year performance period are determined on a compounded basis.

If targets are not met, there is the potential for no payouts. If targets are exceeded, payouts may be as much as, but not more than, two times the initial grant value.

The performance targets for the 2009 RSU awards may constitute forward-looking information. Forward-looking statements are based upon a number of assumptions and are subject to a number of known and unknown risks and uncertainties, any of which are beyond Emera's control, which could cause actual results to differ materially from the performance targets. Please see the cautionary statement in the 2009 Annual

Report respecting risks and assumptions relevant to Emera's determination of performance targets for compensation purposes.

The amount payable to Named Executive Officers at the end of the three-year performance period is determined by:

(a) the number of RSUs held;
(b) the average 50 trading-day share price as at the end of the three-year performance period; and
(c) Emera's financial performance against the two equally-weighted performance factors over the three-year performance period.

If a participant leaves Emera's employment prior to the payout date and is under the age of 55 at the date of termination, the participant is not entitled to a payout for that particular grant of RSUs. An exception to this would be in the event of the death of a participant.

If, prior to the payout date a participant:

i) leaves Emera's employment between age 55 and 65 and does not work for, or on behalf of, one of Emera's competitors; or
ii) retires on or after age 65,

they will be eligible to receive a pro-rated portion of the payout for that particular grant based on the period during which they were employed by Emera during the three-year performance period. The payout will be made after the end of the three-year performance period.

If a participant dies prior to the payout date, their named beneficiary will be eligible to receive a pro-rated portion of the payout based on the period during which they were employed during the three-year performance period for that particular grant. The payout will be made after the end of the three-year performance period.

Senior Management Stock Option Plan

The administration of the Senior Management Stock Option Plan (the "Stock Option Plan") has been delegated to the MRCC by the Board of Directors. Under the Stock Option Plan, the MRCC is responsible for designating, based on Management's recommendation, which employees of the Company and its affiliates will be eligible to participate in the Stock Option Plan. All of the Named Executive Officers are participants in the Stock Option Plan and have received stock options in 2009 as a part of their long-term incentive.

Options are currently designed to deliver a percentage of the long-term incentive opportunity for senior management, including the Named Executive Officers, and have been maintained to recognize their importance as a component of competitive executive compensation and to preserve a long-term focus. The level of grant increases with the level of responsibility.

Options are granted to selected employees of the Company and its affiliates and may be exercised for up to a maximum of ten years. All options granted to date are exercisable on a graduated basis with up to 25 percent of the options exercisable on the first anniversary date and in further 25 percent increments on each of the second, third, and fourth anniversaries of the grant. If an option is not exercised within ten years, it expires and the employee loses all rights thereunder. The holder of an option has no rights as a shareholder until the option is exercised and shares have been issued. The price at which stock options may be exercised is the closing market price of the Company's common shares on the Toronto Stock Exchange on the last business day on which such shares were traded immediately preceding the effective date of the grant of an option.

Unless the term of an option has expired, options may be exercised within the 24 months following the date of retirement or termination for other than just cause, and within six months following the date of termination for just cause, resignation, or death.

The maximum percentage of shares under all security-based compensation (including the Stock Option Plan) issuable to insiders of the Company at any time is ten percent of the issued and outstanding shares of the Company.

The maximum number of shares to be optioned to any one person under the Stock Option Plan is five percent of the issued and outstanding shares of the Company at the date of the grant of the option.

The number of shares issued to insiders, within any one-year period, under all security-based compensation arrangements, will not exceed ten percent of the issued and outstanding shares of the Company.

The table below summarizes certain ratios regarding the Stock Option Plan, namely dilution, burn rate and overhang as defined in the table and measured as a percentage of the total number of shares outstanding as of December 31, 2009, 2008 and 2007.

	Dec. 31 2009	Dec. 31 2008	Dec. 31 2007
Dilution *(total number of options outstanding divided by total number of shares outstanding)*	1.84%	1.96%	2.10%
Burn Rate *(total number of options granted in a fiscal year, minus expired options, divided by the total number of shares outstanding)*	0.33%	0.21%	0.41%
Overhang *(total shares available for issuance plus options outstanding, divided by the total number of shares outstanding)*	5.50%	5.93%	6.41%

Stock options issued under the Stock Option Plan are non-assignable other than by Will or pursuant to the laws of succession.

The Board of Directors of the Company may amend or discontinue the Stock Option Plan by resolution at any time; provided, however, that no such amendment:

- results in any extension of the term of a stock option benefitting an optionee; or
- results in any reduction to the exercise price of a stock option benefitting an optionee; or
- increases the maximum number of shares that may be optioned under the Stock Option Plan; or
- changes the manner of determining the option price; or
- without the consent of the optionee, alters or impairs any stock option previously granted to an optionee under the Stock Option Plan.

Any amendment to the Stock Option Plan may be subject to the approval of regulatory authorities, including the listing requirements of the Toronto Stock Exchange and other stock exchanges and may require shareholder approval.

In 2009, the Company provided no financial assistance to participants under the Stock Option Plan to facilitate the purchase of shares under the Plan.

Other Executive Benefits

The Company provided executives with additional benefits in accordance with the compensation program objectives and for the purpose of retention and motivation. As part of their compensation, the Named Executive Officers are eligible to receive:

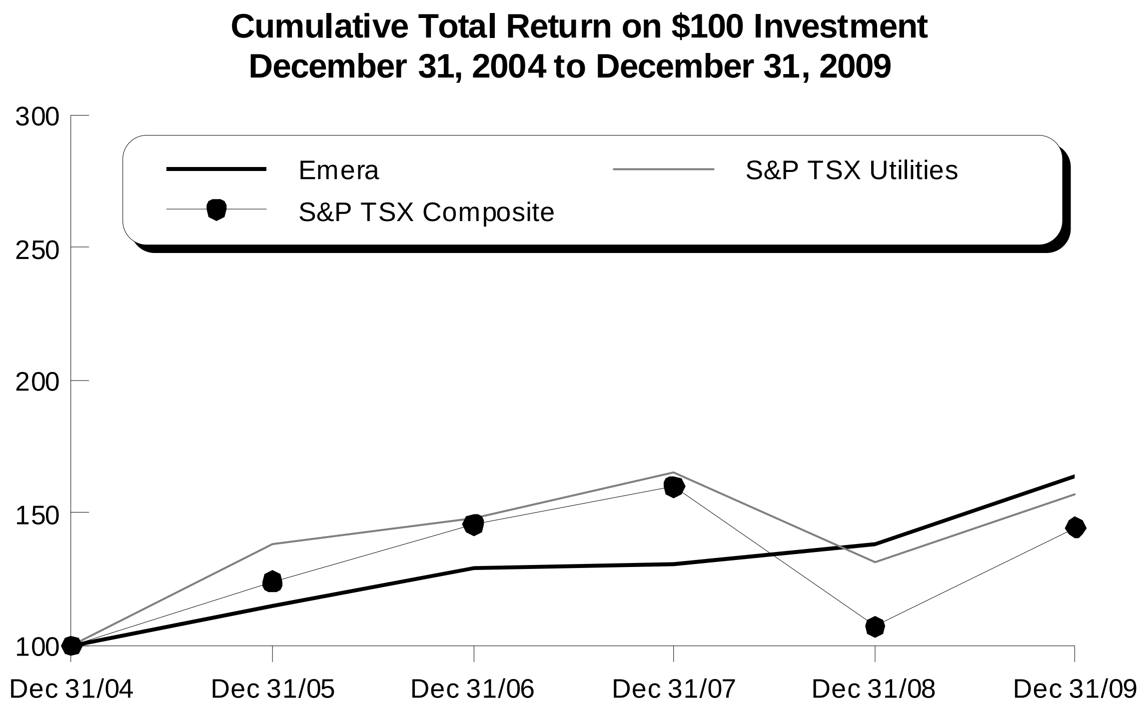
- Life and Accidental Death and Dismemberment (ADD) Insurance coverage of five times annual base salary to a maximum of $1,000,000 ($1,500,000 for the President and Chief Executive Officer);
- supplementary retirement plan contributions for amounts beyond the allowable Canada Revenue Agency pension limits;
- annual income tax return preparation in conjunction with retirement planning;
- monthly parking;
- monthly car allowance plus mileage, as applicable; and
- an annual wellness/fitness allowance for a recreational and/or social club.

Some of these items are considered as taxable benefits and are reported in the Summary Compensation Table for the Named Executive Officers.

All retired employees may be eligible to continue basic life and accident insurance as well as extended health coverage.

Performance Graph

The following performance graph compares the Company's cumulative total shareholder return (assuming an investment of $100 and reinvestment of dividends) for its shares with that of the S&P TSX Utilities Index and the S&P TSX Composite Index.



	Dec. 31/04	Dec. 31/05	Dec. 31/06	Dec. 31/07	Dec. 31/08	Dec. 31/09
Emera	$100.00	$115.05	$129.21	$130.62	$138.38	$164.03
S&P TSX Utilities	100.00	138.29	147.98	165.57	131.69	156.72
S&P TSX Composite	100.00	124.13	145.55	159.86	107.10	144.65

From 2004 to 2009, total annual earnings and annual incentive for the top five Named Executive Officers increased by 25.4 percent. The cumulative total shareholder return for Emera during the same period was 64.03 percent. The chart above shows the steady growth of Emera during the past five years from 2004 to 2009, which has exceeded market comparators (7.3 percent more than the S&P TSX Utilities Index and 19.4 percent more than the S&P TSX Composite Index) and delivered total shareholder returns of more than 64 percent. During the same period, total annual earnings and total annual incentive for the top five Named Executive Officers who have led this significant performance increased 25.4 percent.

The total annual base salary, annual incentive and long-term Restricted Share Unit payouts earned in 2009 for the Named Executive Officers totaled $4,339,172 which represents 2.46% of the Company's net earnings applicable to common shares of $175,700,000 for the period ended December 31, 2009.

Summary Compensation Table

Name and Principal Position	Year	Salary (1) ($)	Share Based Awards (2) ($)	Option Based Awards (3) ($)	Non-equity Incentive Plan Compensation: Annual Incentive Plans (4) (5)(6) ($)	Subtotal ($)	Pension Value (7) ($)	All Other Compensation (8) ($)	Total Compensation ($)
C.G. Huskilson President and Chief Executive Officer Emera Inc	2009	649,038	421,820	421,931	693,750	2,186,539	249,000	20,438	2,455,977
	2008	623,076	632,813	210,938	468,750	1,935,577	427,000	24,491	2,387 068
N.G. Tower Vice-President and Chief Financial Officer Emera Inc. and Nova Scotia Power Inc.	2009	321,385	162,795	54,216	316,600	854,996	85,000	16,866	956,862
	2008	299,423	157,500	52,500	187,500	696,923	115,000	16,452	828,375
R.R. Bennett President and Chief Executive Officer Nova Scotia Power Inc.	2009	336,692	146,309	48,694	195,240	726,935	286,000	24,260	1,037,195
	2008	274,487	416,256	24,375	113,026	828,144	444,000	19,946	1,292,090
R.J.S. Hanf(9) Chief Executive Officer Bangor Hydro Electric Company	2009	267,706	97,610	32,379	122,388	520,083	37,000	9,601	566,684
	2008	265,149	84,448	28,060	70,344	448,001	68,000	7,962	523,963
W.D. O'Connor Chief Operating Officer Emera Energy Inc.	2009	274,539	82,385	27,610	345,000	729,534	24,750	11,921	766,205
	2008	234,078	40,000	50,000	255,000	579,078	15,600	62,031	656,709

Notes:

(1) Salary information is based on actual earnings.

(2) Includes DSU special awards and RSU grants. It does not reflect DSUs received in lieu of cash bonuses. See 'Deferred Share Unit Plan' for further details. For 2009 the initial value of an RSU was based on the average 50 trading-day share price on December 31, 2008 ($21.41) multiplied by a value ratio factor of 1.111 resulting in an expected value of an RSU to be $23.79.

(3) The value of stock option grants is based on the Black-Scholes valuation methodology. Stock options granted to the Named Executive Officers in 2009 were based on the Black-Scholes value which was determined to be equal to 11.4 percent of the closing share price of $21.99 as of February 12, 2009.

(4) In 2009 Mr. C.G. Huskilson and Ms. N.G. Tower participated in the Emera Corporate Scorecard which included specific financial targets of earnings per share (60 percent), cash flow per share (30 percent), and leadership of people (10 percent). In 2009 earnings per share were $1.55 (excluding a mark-to-market adjustment for 2009) which was over target or 120 percent; cash flow per share was slightly over target at $2.94 or 42 percent; and the Leadership measure achieved target and paid out at 10 percent. Based on these year-end results, it was determined by the MRCC that the Named Executive Officers for Emera achieved 172 percent of target on the Emera Corporate Scorecard.

In 2009 Mr. R.R. Bennett participated in the NSPI Corporate Scorecard which included specific financial targets of financial earnings and free cash flow (40 percent), service reliability and customer satisfaction (30 percent), asset management (15 percent), safety excellence (7.5 percent), and leadership of people (7.5 percent). Based on year-end results, it was determined by the MRCC that Mr. Bennett achieved 134.8 percent of target on the NSPI Corporate Scorecard.

In 2009 Mr. R.J.S. Hanf participated in the BHE Corporate Scorecard which included specific financial targets of earnings per share and net income (55 percent), customer satisfaction (20 percent), asset management (10 percent), safety performance (7.5 percent) and people/workplace excellence (7.5 percent). Based on year-end results it was determined by the MRCC that Mr. Hanf achieved 131.25% of target on the BHE Corporate Scorecard.

The 2009 annual incentive for the Named Executive Officer for Emera Energy Inc., Mr. W.D. O'Connor, is based on the year-end financial results of Emera Energy Inc. and based on an assessment of achievement of objectives, including progress on new business development and human resource development.

(5) The non-equity incentive plan compensation reflects amounts earned within the 2009 performance year and paid in 2010. Mr. C.G. Huskilson elected not to receive any of his 2009 annual incentive in DSUs. Ms. N.G. Tower elected to receive 50% of her 2009 annual incentive ($133,300) in DSUs. Mr. R.R. Bennett elected to receive 50% of his 2009 annual incentive ($87,620) in DSUs. Mr. R.J.S. Hanf elected not to receive any of his 2009 annual incentive in DSUs. Mr. W.D. O'Connor elected to receive 50% of his 2009 annual incentive ($172,500) in DSUs.

(6) The 2009 non-equity incentive plan compensation for Mr. C.G. Huskilson includes a lump sum amount of $48,750 in lieu of a base salary adjustment in 2009. The 2009 non-equity incentive plan compensation for Ms. N.G. Tower includes a bonus amount of $50,000 for work completed on a business development acquisition during the year. The 2009 non-equity incentive plan compensation for Mr. R.R. Bennett includes a bonus amount of $20,000 for additional project work completed outside of the NSPI Corporate Scorecard. The 2009 non-equity plan compensation for Mr. R.J.S. Hanf includes a bonus amount of $20,000 for additional project work completed outside of the BHE Corporate Scorecard.
(7) Further information concerning pension values can be found in the section entitled "Pension Plan Benefits".
(8) As part of their compensation, the Named Executive Officers are eligible to receive Life and Accidental Death and Dismemberment (ADD) Insurance coverage of five times annual base salary to a maximum of $1,000,000 ($1,500,000 for the President and Chief Executive Officer); supplementary retirement plan contributions for amounts beyond the allowable Canada Revenue Agency pension limits; annual income tax return preparation in conjunction with retirement planning; monthly parking; monthly car allowance plus mileage, as applicable; and an annual wellness/fitness allowance. These items are included in the All Other Compensation column and some of these items are considered taxable benefits. Mr. Bennett's All Other Compensation includes an amount of $1,998 that reflects the taxable benefit on his outstanding interest-free loan. The costs of the benefits are based on the costs incurred by the Company except in the case of the interest-free loan to Mr. Bennett which is based on an imputed interest rate of 3.0% per annum.
(9) Salary information for Mr. R.J.S Hanf has been converted to CDN dollars based on an exchange rate of 1.046.

Outstanding Share-Based Awards and Option-Based Awards

The following table describes all option-based and share-based awards outstanding as of December 31, 2009 for each Named Executive Officer.

	Option-based Awards (1) (Stock Options)				Share-based Awards (Restricted Share Units (RSUs) and Deferred Share Units (DSUs))	
Name	Number of Securities Underlying Unexercised Options (#)	Option Exercise Price ($)	Option Expiration Date	Value of Unexercised in-the-money Options ($) (2)	Number of Shares or Units of Shares That Have Not Vested (#) (3)	Market or Payout Value of Share-Based Awards That Have Not Vested ($) (4)
C.G. Huskilson	168,100	21.99	February 12, 2019	517,748	98,241	2,462,902
	79,500	21.58	February 14, 2018	277,455		
	163,800	20.42	March 8, 2017	761,670		
	172,900	19.88	March 16, 2016	897,351		
	160,200	19.50	February 9, 2015	892,314		
	90,000	17.79	February 5, 2014	655,200		
	69,000	15.73	February 5, 2013	644,460		
	59,300	16.50	February 13, 2012	508,201		
	28,200	16.75	February 8, 2011	234,624		
N.G. Tower	21,600	21.99	February 12, 2019	66,528	18,415	461,664
	21,500	21.58	February 14, 2018	75,035		
	42,100	20.42	March 8, 2017	195,765		
	30,500	19.88	March 16, 2016	158,295		
	19,600	19.50	February 9, 2015	109,172		
	14,400	17.79	February 5, 2014	104,832		
	9,000	15.73	February 5, 2013	84,060		
	4,750	17.55	October 27, 2012	35,720		
R.R. Bennett	19,400	21.99	February 12, 2019	59,752	23,720	594,660
	10,000	21.58	February 14, 2018	34,900		
	12,600	20.42	March 8, 2017	58,590		
	14,100	19.88	March 16, 2016	73,179		
R.J.S. Hanf	12,900	21.99	February 12, 2019	39,732	8,302	208,131
	11,500	21.58	February 14, 2018	40,135		
	10,550	20.42	March 8, 2017	49,058		
	5,800	19.88	March 16, 2016	30,102		
W.D. O'Connor	11,000	21.99	February 12, 2019	33,880	5,528	138,587
	19,600	22.59	June 1, 2018	48,608		

Notes:
(1) Option-based awards include both vested and unvested options.
(2) The value of all unexercised option-based awards was calculated using a December 31, 2009 closing share price of $25.07.
(3) Unvested share-based awards include initial Restricted Share Unit (RSU) and Deferred Share Unit (DSU) grants and any additional RSUs and DSUs from dividend reinvestment as of December 31, 2009.
(4) Share-based awards values were calculated based on an assumed performance factor of 1 and a December 31, 2009 closing share price of $25.07.

Incentive Plan Awards – Value Vested or Earned During the Year

The following table describes the value of all option-based awards, share-based awards, and non-equity incentives that vested or were earned during 2009 for each Named Executive Officer.

Name	Option-based awards Value vested during 2009 (1) ($)	Share-based awards (Restricted Share Units (RSUs) and Deferred Share Units (DSUs)) Value vested during 2009 (2)(3) ($)	Non-equity incentive plan compensation - Value earned during the year (4) ($)
C.G.Huskilson	94,919	613,034	693,750
N.G. Tower	11,613	252,087	316,600
R.R. Bennett	0	114,272	195,240
R.J.S. Hanf	0	78,993	122,388
W.D. O'Connor	0	59,225	345,000

Notes:
(1) Represents the aggregate dollar value that would have been realized if the options under the option-based award had been exercised on the vesting (eligibility) date in 2009.
(2) This dollar amount represents the payout of 2007 RSU grants based on the performance factors established in 2007. In 2009, the value of share-based awards vested during the year reflects performance factors based on Emera's relative performance versus the S&P/TSX Capped Utilities Total Return Index and the Canada Long-Term Bond Index plus 3.5 percent. The payout at the end of the three-year performance period is calculated based on vested RSUs x Performance Factors x Period Ended Share Price. The overall performance factor was 1.387. The average share price during the last five trading days of 2009 was $25.01.
(3) This dollar amount includes the value of DSUs vested in 2009 and calculated at a December 31, 2009 share price of $25.07. In 2009 for Ms. N.G. Tower this amount equaled $94,564 and for Mr. R.R. Bennett this amount equaled $67,463.
(4) This dollar amount represents the 2009 incentive payout as previously discussed in the Summary Compensation Table.

Aggregated Option Exercises during 2009 and 2009 Option Values

The following table summarizes for each of the Named Executive Officers the number of common shares acquired pursuant to the exercise of stock options during the fiscal year ended December, 31, 2009, if any; the aggregate value realized upon exercise, if any; and the number of common shares covered by unexercised options under the Stock Option Plan as at December 31, 2009. Aggregate value realized upon exercise, if any, is the difference between the fair market value of the common shares on the exercise date and the exercise or base price of the option. Value of unexercised in-the-money options at fiscal year-end, if any, is the difference between the exercise or base price of the options and the fair market value of the common shares on December 31, 2009 which was $25.07.

Name	Securities Acquired on Exercise (#)	Aggregate Value Realized ($)	Unexercised Options at December 31, 2009 Exercisable (#)	Unexercisable (#)	Value of Unexercised In-the-Money Options at December 31, 2009 Exercisable ($)	Unexercisable ($)
C.G. Huskilson	22,000	220,000	638,150	352,850	4,058,011	1,331,012
N.G. Tower	Nil	N/A	97,050	66,400	569,147	260,260
R.R. Bennett	Nil	N/A	19,375	36,725	92,904	133,517
R.J.S. Hanf	27,950	100,792	2,875	37,875	10,034	148,993
W.D. O'Connor	Nil	N/A	4,900	25,700	12,152	70,336

Pension Plan Benefits

The Named Executive Officers are members of the corporate pension plan and may participate in either a defined benefit basis or a defined contribution basis.

Defined Benefit

The following table shows years of credited service, estimated pension amounts, and changes to accrued obligations from January 1, 2009 to December 31, 2009 for the Named Executive Officers who participate in the corporate pension plan on a defined benefit basis.

Name	Number of Years Credited Service (#)	Annual Benefits Payable At Year End[(1)] ($)	Annual Benefits Payable At Age 65 ($)	Accrued Obligation at Start of Year ($)	Compensatory Change[(2)] ($)	Non-Compensatory Change ($)	Accrued Obligation at Year End ($)
C.G. Huskilson	29.58	421,000	498,000	4,899,000	249,000	1,388,000	6,536,000
N.G. Tower	12.33	81,000	174,000	756,000	85,000	264,000	1,105,000
R.R. Bennett	21.67	108,000	174,000	1,008,000	286,000	467,000	1,761,000
R.J.S. Hanf	7.5	35,000	120,000	236,000	37,000	115,000	388,000

Notes:

(1) Not eligible for immediate pension at year-end, amount shown is the amount payable starting at age 65 if Named Executive Officer terminated employment at December 31, 2009.

(2) Reflects change in accrued benefit obligation related to a) the employer cost of the additional pension service earned during 2009 and b) changes in pensionable earnings different than what was assumed.

The defined benefit component of the plan entitles members to pension benefits based on two percent (less an offset for Canada Pension Plan (CPP)) of the average of the four highest years' earnings multiplied by each year of credited service to a maximum of 35 years credited service. Upon reaching age 65, pension benefits under the pension plan are reduced to reflect commencement of payments under the CPP. In addition, the Named Executive Officers are eligible to have portions of their annual incentive included in pensionable earnings.

The pension is payable upon the earlier of age 60 or age 55, provided that age and years of service add to at least 85. A member may also retire on a reduced formula if the member has attained age 55, but does not qualify for the rule of 85.

Members of the defined benefit component of the plan contribute 5.4 percent of eligible earnings up to the year's maximum pensionable earnings ("YMPE") under the Canada Pension Plan, and seven percent of earnings between the YMPE and the amount on which pension benefits may be earned under a registered pension plan as permitted by the *Income Tax Act,* (Canada).

Spousal benefits are paid on the death of a member at the rate of 60 percent of regular pension benefits. The pension plan is indexed to the consumer price index to a maximum of six percent per annum.

Due to Canada Revenue Agency's limitations on the maximum pension benefit which may be paid under the pension plan, a portion of the pension earned after January 1, 1992 is provided under the terms of a Supplementary Employee Retirement Plan which is secured by a letter of credit deposited in a retirement compensation trust.

The accrued pension obligation is calculated following the method prescribed by the Canadian Institute of Chartered Accountants and is based on management's best estimate of future events that affect the cost of pensions, including assumptions about future salary adjustments and annual incentive award.

Defined Contribution

The following table shows accumulated value, estimated pension amounts, and changes to accrued obligations from January 1, 2009 to December 31, 2009 for the Named Executive Officer who participates in the corporate pension plan on a defined contribution basis.

Name	Accumulated Value at Start of Year ($)	Compensatory ($)	Non-Compensatory ($)	Accumulated Value at Year End ($)
W.D. O'Connor	70,100	24,750	34,650	129,500

The defined contribution component of the plan is a registered pension plan regulated by the *Income Tax Act* and the *Nova Scotia Pension Benefits Act*. Accordingly, contributions are deductible for income tax purposes.

The Company contributes a base amount to the participant's account each pay period. The amount is expressed as a percentage of eligible earnings. Plan participants can also make contributions to the defined contribution component with the Company matching a portion of these contributions. Canada Revenue Agency limits apply.

Upon ending active employment with the Company at any age between 55 and 65, plan participants may start receiving retirement income through the purchase of a life annuity or by converting their account to a Life Income Fund (LIF).

The defined contribution component of the plan is administered on behalf of the Company by a major Canadian insurance company which acts in accordance with the provisions of the defined contribution component of the plan, the *Income Tax Act*, and the *Nova Scotia Pension Benefits Act.*

Mr. O'Connor participates in the defined contribution component of the plan. Under the terms of the defined contribution component, Mr. O'Connor and the Company each contribute six percent of his base salary into the registered pension plan up to the total amount permitted under the *Income Tax Act*. For 2009 Mr. O'Connor and the Company each contributed $11,000. In addition, the Company maintains an account for any Company contributions which would be made in the absence of the *Income Tax Act* limits. For 2009, the additional Company contribution was $13,750.

Deferred Share Unit Plan ("DSU Plan")

Emera has a DSU Plan for executives and senior management and each Named Executive Officer is a participant.

A Deferred Share Unit ("DSU") is a bookkeeping entry that has a value based upon the value of one common share of the Company. Each DSU earns dividend equivalents in the form of additional DSUs. DSUs are not paid out until such time as the participant is no longer employed by the Company or any of its affiliates. When redeemed, the value of a participant's DSUs is equivalent to the fair market value of an equal number of common shares of the Company.

Prior to the start of each financial year, the Named Executive Officers provide elections respecting the portion of their upcoming Annual Incentive, if any, which is to be allocated to DSUs. When the Annual Incentive is paid to the Named Executive Officers, the amount elected is allocated to DSUs rather than paid in cash. Each DSU has a value equal to the market price of a Company common share.

The table below identifies the amount of annual incentive for 2009 which each Named Executive Officer elected to receive as DSUs.

Name	Percentage of 2009 Annual Incentive Elected to Deferred Share Units (%)	Dollar Amount of 2009 Annual Incentive Elected to Deferred Share Units ($)
C.G. Huskilson	0%	Nil
N.G. Tower	50%	$133,300
R.R. Bennett	50%	$87,620
R.J.S. Hanf	0%	Nil
W.D. O'Connor	50%	$172,500

When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividend paid on an equivalent number of Emera common shares.

Following resignation, termination of employment or retirement, and on a date selected by the participant later than December 15 of the next calendar year after resignation, termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the then market value of an Emera common share. The after-tax amount is paid to the participant. If a participant is a U.S. taxpayer, payment shall be made six months following the termination date.

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or to achieve certain corporate objectives. Special DSU awards vest over a three to five year period and should the recipient leave the Company prior to the vesting date, those DSUs not yet vested will be forfeited.

Executive Share Ownership Requirements

To align the interests of senior management with the interests of shareholders, share ownership guidelines were introduced for designated Executive Officers in 2003. The guidelines, which must be achieved within five years of becoming a designated Executive Officer, are as follows:

President and Chief Executive Officer, Emera	3.0 times salary
President and Chief Executive Officer, Nova Scotia Power Inc. & Bangor Hydro Electric Co.	2.0 times salary
Chief Operating Officer and Senior Vice Presidents	1.5 times salary
Vice Presidents	1.0 times salary

Share ownership is based on the number of shares owned by an individual, plus Deferred Share Units (DSUs) which may be acquired pursuant to the Company's DSU Plan. DSUs are considered share equivalents.

The DSU Plan is intended to facilitate achievement of share ownership guidelines without diluting the shareholder base. DSUs are an income deferral mechanism only, and therefore there are no performance targets attributable to DSUs.

Under the DSU Plan, each participant may elect to defer all or a percentage of the annual incentive award in the form of DSUs until the applicable guidelines are met.

The share and/or share equivalent ownership for those Named Executive Officers governed by the ownership guidelines is set out below. The estimated value is based on the closing price of Emera's common shares on December 31, 2009 of $25.07. Mr. C.G. Huskilson, Ms. N.G. Tower, and Mr. W.D. O'Connor have exceeded the guidelines. Mr. R.R. Bennett was appointed President and Chief Executive Officer of NSPI in June 2008, and has until June 2013 to meet the executive share ownership guidelines. Mr. R.J.S. Hanf was appointed President and Chief Operating Officer of Bangor Hydro in October 2008 and has until October 2013 to meet the Executive Share Ownership Guidelines.

Named Executive Officer	Shares/Share Equivalents [1] (#)	Estimated Value ($)
C.G. Huskilson	173,521	4,350,171
N.G. Tower	33,470	839,093
R.R. Bennett	23,761	595,688
R.J.S. Hanf	5,590	140,141
W.D. O'Connor	17,334	434,563

Notes:
(1) Includes vested and not yet vested DSUs calculated at a December 31, 2009 closing share price of $25.07.

Three-Year Compensation Information for President and Chief Executive Officer, Emera Inc.

The following table shows the three-year history for compensation for C.G. Huskilson, Emera's President and Chief Executive Officer.

	2009 ($)	2008 ($)	2007 ($)
Cash Compensation			
Base Salary	649,038	623,076	568,104
Annual Incentive (1)	645,000	468,750	306,188
Additional Bonus Paid	48,750	0	0
Total Annual Cash Compensation	1,342,788	1,091,826	874,292
Equity Component			
Value of stock options at grant date (2)	421,931	210,938	388,206
Value of restricted share units at grant date	421,820	632,813	388,049
Value of awarded deferred share units at vesting date (3)	0	0	99,600
Total value of equity under the annual grant	843,751	843,751	875,855
Total Direct Compensation	2,186,539	1,935,577	1,750,147
Benefit Compensation			
Compensatory Elements of pension cost (4)	249,000	427,000	1,209,000
Term Life Insurance premiums	7,240	6,351	4,642
Total	**2,442,779**	**2,368,928**	**2,963,789**

Notes:

(1) Mr. C.G. Huskilson elected to receive 0% of his 2009 annual incentive in DSUs.

(2) The value of the stock option grants are estimated grant date values only. In 2009 grants of stock options made up 50% of the Long Term Incentive and restricted share units made up 50% of the Long Term Incentive.

(3) This amount reflects special Deferred Share Unit grants only. It does not reflect DSU elections made in lieu of cash bonuses. No special grants vested in 2009.

(4) Figures shown represent pension cost based on actuarial calculations.

Termination and Change of Control Benefits

The following table provides the estimated amounts of incremental payments, payables and benefits to which each Named Executive Officer would be entitled under various plans and arrangements, assuming resignation, termination without cause, termination for cause, and separation from the Company in circumstances of a change of control, assuming the triggering event took place on December 31, 2009. This table does not reflect payments to which the Named Executive Officers were already entitled to under the current compensation plan design.

Name	Termination Scenario(1)	Cash Severance ($)	Short Term Incentive ($)	Restricted Share Units (RSUs) ($)	Deferred Share Units (DSUs) ($)	Stock Options ($)	Continuation of Benefits (Present Value)(2) ($)	Total ($)
C.G. Huskilson	Voluntary / For Cause							
	Not for Cause	1,250,000	750,000		1,244,775		40,000	3,284,775
	Change of Control	1,250,000	750,000	1,218,126	1,244,775		40,000	4,502,901
N.G. Tower	Voluntary / For Cause							
	Not for Cause	310,000	155,000	184,743	94,564		12,000	756,307
	Change of Control	310,000	155,000	367,100	94,564			926,664
R.R. Bennett	Voluntary / For Cause							
	Not for Cause	325,000	130,000	111,790	346,116		12,000	924,906
	Change of Control	325,000	130,000	248,544	346,116			1,049,660
R.J.S. Hanf	Voluntary / For Cause							
	Not for Cause	375,000	78,000					453,000
	Change of Control							
W.D. O'Connor	Voluntary / For Cause							
	Not for Cause	275,000	345,000					620,000
	Change of Control							

Notes:

(1) Change of Control scenarios also assume all unvested RSUs would become payable in full and are valued based on an assumed performance factor of 1 and a year end closing share price of $25.07. Change of control scenarios also assume all DSUs would vest and are valued based on a year end closing share price of $25.07.

(2) Continuation of benefits reflect amounts for car allowance and health and dental benefits.

The following is a summary of termination and change of control benefits afforded to each Named Executive Officer under his or her employment contract.

C.G. Huskilson, President and Chief Executive Officer, Emera

If Mr. Huskilson resigns his position he will be entitled to all compensation and benefits up to the effective date of resignation.

If Mr. Huskilson is terminated for cause, he will not be entitled to compensation upon or following such termination.

If he is terminated without cause, he shall be entitled to 24 months' compensation based upon annual salary, annual incentive at target, and car allowance in effect at the time, salary to termination date, any accrued but unused vacation time, health, dental and other such benefits for 12 months.

If there is a change of control of the ownership of the Company, such that any one party acquires 50 percent or more of voting securities and there is a substantial reduction in responsibilities or scope of authority, Mr. Huskilson may elect within three months following such substantial reduction in responsibilities or scope of authority to terminate employment and receive 24 months' compensation and 12 months of benefits.

Under any termination of employment by the Company, or as a result of death, all entitlement to

Deferred Share Units (DSUs) previously granted in May 2006, which have not yet been vested at the date of such termination, or death shall vest immediately.

Mr. Huskilson becomes eligible to retire with an unreduced pension on June 30, 2012. He has agreed to advise the Company at least one year in advance of any proposed retirement. Information regarding pension entitlement is contained in the section entitled “Pension Plan Benefits”.

Under all scenarios, unless otherwise noted, Mr. Huskilson shall be entitled to payments associated with RSUs, DSUs, and Stock Options according to the terms and conditions of the plans.

N.G. Tower, Vice-President and Chief Financial Officer, Emera Inc. and Nova Scotia Power Inc.

If Ms. Tower resigns her position she will be entitled to compensation and benefits up to the effective date of resignation.

If Ms. Tower is terminated for cause, she will not be entitled to compensation upon or following such termination.

In the event of termination without cause, she is entitled to a lump sum equal to 12 months’ compensation based upon annual salary, annual incentive at target, and car allowance in effect at the time, salary to termination date, any accrued but unused vacation time, health, dental and other such benefits for 12 months or until she obtains new employment benefit coverage.

In addition, if Ms. Tower is terminated without cause prior to July 12, 2010, the special Deferred Share Unit grant received in 2007 will vest immediately.

Any unvested Restricted Share Units (RSUs) held at the date of termination will be prorated.

If there is a change of control of the ownership of the Company, such that any one party acquires 50 percent or more of voting securities and there is a substantial reduction in responsibilities or scope of authority, Ms. Tower may elect, within three months following such substantial reduction in responsibilities or scope of authority, to terminate employment and receive 12 months’ compensation calculated on the basis of her annual salary and target bonus then in effect.

Ms. Tower becomes eligible to retire with an unreduced pension on March 31, 2019. Information regarding pension entitlement is contained in the section entitled “Pension Plan Benefits”.

Under all scenarios, unless otherwise noted, Ms. Tower shall be entitled to payments associated with RSUs, DSUs, and Stock Options according to the terms and conditions of the plans.

R.R. Bennett, President and Chief Executive Officer, Nova Scotia Power Inc.

If Mr. Bennett resigns his position he will be entitled to compensation and benefits up to the effective date of resignation.

If Mr. Bennett is terminated for cause, he will not be entitled to compensation upon or following such termination.

In the event of termination without cause, he is entitled to a lump sum equal to 12 months’ compensation based upon annual salary, annual target bonus and car allowance in effect at the time, salary to termination date, any accrued but unused vacation time, health, dental and other such benefits for 12 months.

In addition, if Mr. Bennett is terminated without cause any special Deferred Share Unit grants received in 2008 will vest immediately.

Any unvested Restricted Share Units (RSUs) held at the date of termination will be prorated.
If there is a change of control of the ownership of the Company, such that any one party acquires 50 percent or more of voting securities and there is a substantial reduction in responsibilities or scope of authority, Mr. Bennett may elect, within three months following such substantial reduction in responsibilities or scope or authority, to terminate employment and receive 12 months’ compensation calculated on the basis of his annual salary and target bonus then in effect.

Mr. Bennett becomes eligible to retire with an unreduced pension on October 31, 2017. Information regarding pension entitlement is contained in the section entitled “Pension Plan Benefits”.

Under all scenarios, unless otherwise noted, he shall be entitled to payments associated with RSUs, DSUs, and Stock Options according to the terms and conditions of the plans.

R.J.S. Hanf, Chief Executive Officer, Bangor Hydro Electric Company

If Mr. Hanf resigns his position he will be entitled to compensation and benefits up to the effective date of resignation.

If Mr. Hanf is terminated for cause, he will not be entitled to compensation upon or following such termination.

In the event of termination without cause, he is entitled to a lump sum equal to 12 months' compensation based upon annual salary plus one additional month's salary for each full or partial year of service from January 2007 onward, to a maximum of 24 months; annual incentive at target and car allowance in effect at the time, salary to termination date, any accrued but unused vacation time, health, dental and other such benefits for 12 months.

In addition, Mr. Hanf will be eligible to receive up to $50,000 in relocation and moving expenses.
Mr. Hanf's employment contract does not contain change of control provisions.

Mr. Hanf becomes eligible to retire with an unreduced pension on November 30, 2022. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".

Under all scenarios, unless otherwise noted, he shall be entitled to payments associated with RSUs, DSUs, and Stock Options according to the terms and conditions of the plans.

W.D. O'Connor, Chief Operating Officer, Emera Energy Inc.

If Mr. O'Connor resigns his position he will be entitled to compensation and benefits up to the effective date of resignation.
If Mr. O'Connor is terminated for cause, he will not be entitled to compensation upon or following such termination.

Mr. O'Connor's employment contract does not contain change of control provisions.

In the event of termination without cause, he is entitled to a lump sum equal to 12 months' compensation based upon annual salary in effect at the time, annual salary to termination date, and any accrued but unused vacation time.

Mr. O'Connor becomes eligible to retire in 2020. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".

Under all scenarios he shall be entitled to payments associated with RSUs, DSUs, and Stock Options according to the terms and conditions of the plans.

Shares Authorized for Issuance Under Equity-Based Compensation Plans

The following table shows shares authorized for issuance under the Senior Management Stock Option Plan and the Employee Common Share Purchase Plan as of December 31, 2009. There are no equity-based compensation plans that were not approved by Shareholders.

Plan Category	(A) Number of shares to be issued upon exercise of outstanding options	(B) Weighted-average exercise price of outstanding options	(C) Number of shares available for future issuance under equity compensation plans (excluding column (A))
Equity-based compensation plans approved by shareholders			
- Senior Management Stock Option Plan	2,082,150	$19.99	2,054,200
- Employee Common Share Purchase Plan	N/A	N/A	619,363
Total	2,082,150	$19.99	2,673,563

Aggregate Indebtedness of Directors and Executive Officers and Indebtedness Under Securities Purchase or Other Programs

The Company does not have a program that allows for the provision of loans to Directors or Officers and the Company is not intending to initiate such a program. In addition there is no program to allow loans or indebtedness under any share purchase program.

As of the date of this Circular there was no indebtedness of the Directors to the Company.

As of the date of this Circular, Mr R.R. Bennett, President and Chief Executive Officer, Nova Scotia Power Inc. has an outstanding interest-free loan in the amount of $66,598. This loan was provided to Mr. Bennett to assist with his relocation from Halifax, Nova Scotia to Bangor, Maine at the time of his appointment to a senior management position with Bangor Hydro Electric Company, a subsidiary of Emera. The loan matures and is repayable in full in June 2015. The loan to Mr. Bennett was approved and in place prior to him becoming an officer of Nova Scotia Power Inc.

Material Transactions

During the year, insiders of the Company and its affiliates, including Directors, Executive Officers, proposed nominee Directors or their associates or corporations they controlled, did not have any material interest, direct or indirect, in any transaction or in any proposed transaction that has materially affected or will materially affect the Company.

Management Contracts

There are no functions of management which are performed by a person or company other than the Directors, Executive Officers or other employees of the Company.

Directors' and Officers' Insurance

The Company’s Articles of Association provide for the indemnification of Directors and Officers against liability incurred by them in the proper performance of their duties as Directors and Officers of the Company.

The Company purchases Directors' and Officers' insurance coverage. This coverage provides protection for Directors and Officers in cases where they incur a liability as a result of their activities as a Director or Officer of the Company. For the year ending December 31, 2010 this insurance provides for a maximum coverage of $55,000,000 per claim and in the aggregate. The premium for this insurance is approximately $262,000.

Audit Committee Information

For information regarding Emera’s Audit Committee, including its Charter, composition, relevant education and experience of its members, Audit Committee oversight, policies and procedures for the approval of non-audit services and auditors’ service fees, please refer to Emera’s Annual Information Form available on SEDAR at www.SEDAR.com or by contacting the Corporate Secretary of the Company.

Statement of Corporate Governance Practices

Emera and its Board of Directors are committed to high standards of corporate governance because we believe they are fundamental to achieving strong corporate performance and generating long-term shareholder value. The Board regularly reviews corporate governance to ensure industry best practices are satisfied and to continually improve governance and disclosure. Emera strives to be among the best governed companies in Canada.

The Board of Directors' Nominating and Corporate Governance Committee is responsible for annually reviewing the Company's Corporate Governance Practices and, where appropriate, the Committee recommends revisions to those Practices.

Under the regulations of the Canadian Securities Administrators Emera discloses its corporate governance practices in this Circular. The following is a summary that highlights various elements of those practices.

Summary of Corporate Governance Practices

Board of Directors

Director Independence

Emera values independent judgment in the evaluation of the actions taken by management of the Company. To achieve this outcome, Emera maintains an independent Board and ensures opportunity for deliberation of independent Directors.

All Directors are independent from management, except Christopher G. Huskilson, who is the President and Chief Executive Officer of the Company. No independent Director has any interest, business or other relationship that could interfere, or that could reasonably be perceived to interfere, with his or her ability to act in the best interests of the Company. None of the independent Directors receive remuneration from Emera other than Directors' retainers, fees or retainers for service as Chair of the Board or Chair of a Committee. Mr. G.A. Caines receives a retainer from Emera's subsidiary, Nova Scotia Power Inc. (NSPI) as the Chair of its Board of Directors. Mr. D. Oland also receives Directors' fees from NSPI for attending Board and Committee meetings as a member of the NSPI Board and its Committees.

To assure the Board's independence, the Company's Articles of Association provide that no more than two Directors may be employees of the Company or of a subsidiary or affiliate of the Company. Christopher G. Huskilson, as President and Chief Executive Officer of the Company, is the only Director employed by the Company.

Board of Directors Charter

Emera believes that clear accountabilities lead to the best governance and, therefore, maintains a Charter for the Board. The Board of Directors Charter is attached to this Circular as Appendix "B".

Under the Charter, the Board is responsible to oversee the management of the business of the Company and provide stewardship and governance to ensure the viability and growth of its businesses.

Directors Meet without Management

There were 22 Board or Committee meetings during 2009. At each Board and Committee meeting the Directors hold in-camera sessions to discuss various issues, at which non-independent Directors and members of management are not in attendance.

At most Board and/or Committee meetings, the independent Directors have an in-camera session, including the President and Chief Executive Officer who is not an independent Director, to discuss various issues. The Chair of the Board frequently discusses issues with Directors on an individual basis. The independent Directors also meet to the exclusion of the President and Chief Executive Officer and management, including occasions that are not Board or Committee meetings.

The Board has adopted a practice of holding evening sessions before the day of a formal Board Meeting. As required and at least once a year the independent Directors conduct such an evening session to the exclusion of the President and Chief Executive Officer.

Independent Chair

The Chair of the Board, Mr. John T. McLennan, is an independent Director. The Company mandates that the Chair of the Board and the Chief Executive Officer must be separate individuals at Emera.

Chair of the Board of Directors Mandate

The Chair of the Board of Directors Mandate is attached to this Circular as Appendix A.

Pursuant to this Mandate, the Chair is responsible to lead the Board to fulfill its duties effectively, efficiently and independent of management. The Chair ensures Board and Shareholder meetings function effectively, provides leadership of the Board and its Committees and provides advice and counsel to Directors and the Chief Executive Officer. The Chair participates in the recruitment of Directors and the assessment of their performance.

Directors' Membership on Other Public Company Boards

Emera monitors the participation of Directors on other company's boards to ensure a balance of time is available to attend to Emera's governance needs. Many of the Company's Directors do serve as Directors of other reporting issuers. Details of these positions for each Director are set forth in their biographies earlier in this Circular. Membership on other public company boards is generally viewed positively by Emera in that it provides a Director with additional perspective and insight that is beneficial in performing their duties for the Company, and Emera ensures these other positions do not negatively impact their ability to perform as Directors of the Company.

Board Size

Emera aims for the appropriate number of Directors to ensure the optimal expertise is represented, balanced with the need for quality engagement and dialogue.

The number of Directors on the Company's Board must not be less than eight and not more than fifteen. No more than two Board members may be employees of the Company or of a subsidiary or affiliate of the Company

Nomination of Directors

Emera's Articles of Association and the Charter for the Nominating and Corporate Governance Committee assign the responsibility for recruiting and selecting nominees for election as Directors. The Nominating and Corporate Governance Committee reviews the experience and skill sets of the present Directors and assesses the profiled requirements needed to ensure that the Board is able to function effectively and provide quality oversight to management.

Director Recruiting

The Committee evaluates issues which face, or will face, the Company and provides a plan of action necessary to ensure the Board expertise will be appropriate for Company activities. The Committee uses the services of a qualified search consulting firm in order to assist it in identifying suitable Director candidates. The Board may also develop a list of potential candidates based upon the collective knowledge of the Directors. Potential Director candidates are met by at least the Chair of the Board, the Committee Chair, and the President and Chief Executive Officer, and in most cases by additional Directors. Reference checks and background checks may also be carried out on potential Director candidates.

In 2008, the Nominating and Corporate Governance Committee proactively managed an expected turnover of Directors in advance of their retirement. The Committee implemented an effective succession plan that included creating overlap between new Directors and retiring ones, and which included proactive management of the anticipated succession of the Chair of the Board of Directors.

The Nominating and Corporate Governance Committee is actively searching for Directors in anticipation of upcoming Director retirements.

Director Retirement

The Articles of Association require that a Director retire at the next shareholders' meeting following the date they reach age 70. The Articles also allow the Nominating and Corporate Governance Committee to give consideration to recommending that a Director continue to serve past the age of 70 under certain exceptional circumstances. Any extension to service beyond the age of 70 is for a one-year term and is carefully evaluated by the Committee (see "Nominating and Corporate Governance Committee", below).

Majority Voting for Election of Directors

The confidence of shareholders in the actions of the Board and management are important, and in order to provide a mechanism for shareholders to express that confidence in each Director, the Board adopted a Majority Voting Policy for Directors in February 2008. The Policy states:

> *Should a Director nominee, in an uncontested election at a meeting of shareholders of Emera whereby Directors are to be elected, receive a majority of "withheld" votes for his or*

her election as a Director, the individual shall submit his or her resignation to the Board for consideration promptly following such shareholders' meeting. The votes determining such action shall be those votes validly voted by proxy and those votes validly voted in person at such shareholders' meeting.

The Directors who received a majority "for" vote at the shareholders' meeting shall consider whether or not to accept the resignation submitted by a Director that received a majority of "withheld" votes for his or her election as a Director. If there are less than three such Directors, the entire Board shall consider whether or not to accept the resignation.

A news release disclosing the Board's determination shall be issued within 90 days following the date of the shareholders' meeting. If the resignation is rejected by the Board, the news release shall include the reasons for rejecting the resignation.

Position Descriptions

Chair of the Board

The Chair of the Board has a Mandate that is reviewed by the Nominating and Corporate Governance Committee on an annual basis (see Appendix A to this Circular).

Committee Chairs

All of the Committees have Charters which set out duties and responsibilities. It is the responsibility of each Committee Chair to ensure that the Committee carries out its duties and responsibilities. The various Committees review their Charters on an annual basis and the Charters and Chair's Mandate are annually reviewed by the Nominating and Corporate Governance Committee. The reviews ensure that the duties of the Chair and of each Committee Chair are properly defined and are current with accepted standards.

Position Description for CEO

The roles and responsibilities of the President and Chief Executive Officer are contained in his employment contract and in the Articles of Association which provide that he is chief executive for the Company. The President and Chief Executive Officer's employment contract is negotiated by the Management Resources and Compensation Committee and is approved by the Board of Directors.

Orientation of Directors

Emera believes that for Directors to be effective in their roles, especially upon initial introduction to the Board, they must be knowledgeable about the Company, its strategy, strengths and challenges. As well, effectiveness is enhanced as the new Directors form a collegial working relationship with other members of the Board in order to best bring their skills and knowledge to the operation of the Board.

New Directors to the Emera Board of Directors receive an orientation to the Company that familiarizes them with the businesses, investments and key personnel of the Company and allows them to effectively integrate with other Board members.

Orientation Process

The following are the elements of the orientation process.

Key documents of the business are provided. These include the following:

(a) the most recent Annual Report and Progress Report; Management's Discussion & Analysis (MD&A) and financial statements for the most recent fiscal quarter; most recent Management Information Circular and Annual Information Form:
(b) the Board and Committee Charters;
(c) the most recent Strategic Plan and Business Plan;
(d) a list of the Emera Officers;
(e) Insider Trading Guidelines;
(f) the Emera Group of Companies Standards for Business Conduct;
(g) recent Minutes of the Board and Committees.

An orientation meeting is scheduled. The meeting will include the President and the Chief Financial Officer and such other Executive Officers or leaders of key subsidiaries as the President deems appropriate. The Chair also attends the orientation meetings with the new Director(s), as well as other current Directors.

The purpose of the meetings is to provide new Directors with relevant information about the Company and a forum for discussion with management, the Chair and other Directors. The information includes material about (a) the Company's structure, (b) its strategy, and (c) the human resources of the Company.

A tour of certain sites and facilities is arranged within a reasonable period of time after joining the Board. This includes such facilities as the President deems appropriate and the Directors deem desirable.

The Corporate Secretary's office provides an overview of the running of Board meetings and related governance processes at the Company.

Committee Oversight

This list of orientation activities is reviewed each time that a new Director is elected, and updated as required. The Nominating and Corporate Governance Committee oversees the orientation of new Directors.

Continuing Education for Directors

The oversight of Directors is enhanced when they are well informed about the Company's businesses and its industry. Management continually seeks opportunities to update, educate and inform the Directors in areas they request or that management determines are relevant to issues facing the Company.

The Board is provided with a regular flow of comprehensive information from management to ensure that the Board has sufficient and timely information concerning the Company's activities. This information is used by the Board to assess both the direction of the Company's business and management performance. The Board receives briefing material from management in advance of all meetings. Regular communications are provided to the Directors between meetings to provide updates on developments that might affect Emera's business and that of its subsidiaries.

Guideline for Directors' Attendance at Education Sessions

The Board of Directors adopted a guideline in 2008 for Directors' attendance at education sessions. The purpose of the guideline is to encourage Directors to participate in education sessions from time to time that are directly related to the business of the Company and the performance of their duties as a Director of the Company. The guideline describes the compensation of Directors for attendance at such education sessions. Independent Directors who wish to attend an education session are required to request the approval of the Chair of the Board of Directors to attend a particular education session and receive compensation in accordance with the guideline.

Management Reports

The Board is kept informed of Emera's operations at Board and Committee meetings and through reports from, and regular discussions with, management. The Board is also provided with site visits to operational facilities to assist it in more fully understanding the business and allow the Directors to properly discharge their obligations.

Directors Updates and Briefings

Board and Committee meetings are regularly scheduled and communications between the Board and management occur apart from regularly scheduled Board and Committee meetings in the form of oral and written briefings or specially-called meetings which update Directors on business, operational or technical matters relevant to the Emera group of companies.

Industry Trends

From time to time the Board receives specialized presentations from external parties and/or management on various matters of significance to the Company including presentations on trends in the energy industry, emerging energy technology, energy regulatory trends, changes to accounting treatment and rules, risk management, world fuel supply trends, and environmental interests.

Board Dinners with High Potential Employees

Opportunities are provided for Directors to meet members of senior management identified as high potential candidates in the Company's senior executive succession plan. This provides Directors with the chance to meet and get to know employees that have been identified a potential future leaders in the Company. The Directors may not otherwise necessarily have an opportunity to meet these individuals. Directors are then able to provide feedback which is incorporated into the succession plan. The high potential employees also benefit from this exposure to members of the Board of Directors.

Ethical Business Conduct

The Board recognizes the importance of its leadership in establishing and promoting integrity and ethical business practices throughout the Company.

Corporate Disclosure Policy

The Board encourages and promotes a culture of ethical business conduct. The Board has approved a formal Corporate Disclosure Policy. The purpose of the Disclosure Policy is to ensure that communications to investors and potential investors are timely, factual and accurate, and that the information is disseminated in accordance with all applicable legal and regulatory requirements to the investing public, analysts, and the media.

Standards for Business Conduct

The Board has adopted a written code entitled "The Emera Group of Companies Standards for Business Conduct" (Standards for Business Conduct) for all Directors, officers, and employees. Directors, Officers and employees are required to annually sign an acknowledgement that they have reviewed and understand the Standards of Business Conduct.

A copy of the document is available on Emera's website at www.emera.com or a hardcopy may be obtained by contacting the Vice-President Human Resources, Emera Inc., P.O. Box 910, Halifax, Nova Scotia B3J 2W5.

The Standards for Business Conduct have been implemented throughout the organization. In addition, the Company has adopted a protocol "Procedures for the Reporting of Irregularities and Dishonesty" (otherwise commonly referred to as a whistleblower's policy). Reported violations under the Standards for Business Conduct and Procedures for the Reporting of Irregularities and Dishonesty are addressed by the Company, and on a quarterly basis the Internal Audit department informs the Audit Committee of all reported violations and their status.

There has been no material change report filed that pertains to any conduct of a Director or executive officer that constitutes a departure from the Standards of Business Conduct.

Conflicts of Interest

The Board reviews and approves all material acquisitions, dispositions, projects, business plans, and budgets. The Board ensures Directors exercise independent judgment in considering any transaction. Directors are required to declare any interest which they may have in a matter requiring Board approval and abstain from participation in discussions or voting on the particular matter.

The Directors have also instituted a policy which requires them to submit their resignation as a Director if there is a significant change in their principal occupation. The resignation is then reviewed by the Board or the Nominating and Corporate Governance Committee to determine if the circumstances warrant acceptance of the resignation. This practice serves several purposes including ensuring that the change of principal occupation does not result in a conflict-of-interest situation for the Director and ensuring that the Director is able to maintain the skill, knowledge in business, or other background which resulted in that person initially becoming a member of the Board.

Board Committees

The Board is committed to effective and efficient operation in carrying out its oversight responsibilities. As such, it strongly supports the work of its three Committees to which certain functions are delegated as set forth in written charters. They are:

- the Audit Committee;
- the Management Resources and Compensation Committee; and
- the Nominating and Corporate Governance Committee.

In consultation with the Chair of the Board, the Board and its Committees may retain outside advisors at the Company's expense as they deem necessary.

Audit Committee

The Audit Committee of the Board of Directors assists the Board in discharging its oversight responsibilities concerning the integrity of Emera's financial statements, its internal control systems, the internal audit and assurance process, the external audit process and its compliance with legal and regulatory requirements.

The Committee is comprised of independent Directors only, who are financially literate, none of whom may be employees of Emera, or employees of any affiliate of Emera. The Committee shall be responsible for reviewing and recommending to the Board for approval the annual and interim financial statements and all related management's discussion and analysis.

The Committee evaluates and recommends to the Board the external auditor and the compensation of such external auditor. Once appointed, the external auditor shall report directly to the

Committee, and the Committee oversees the work of the external auditor concerning the preparation or issuance of the auditor's report or the performance of other audit, review or attest services for Emera. The Committee reviews management controls and processes concerning the administration of investment activities, financial reporting, and funding of the pension plans.

The Company's internal auditor also reports directly to the Audit Committee, and the Committee oversees the appointment, replacement, or termination of the internal auditor.

Management Resources and Compensation Committee

The Management Resources and Compensation Committee is comprised of independent Directors only. The Company's Articles of Association require that the Chair of the Board not be a member of the Committee. The Committee reviews overall compensation, including salary and benefit policies and recommends such policies to the Board of Directors.

It reviews corporate goals and objectives relevant to the corporate strategy and recommends such goals and objectives to the Board of Directors. The Committee ensures that an assessment of the President's performance in relation to these goals and objectives, is completed. It makes recommendations to the Board of Directors relating to the President's compensation level, participation in incentive-compensation plans, and equity-based plans based on the Committee's evaluation. It makes recommendations about senior management compensation, incentive-compensation plans, and equity-based plans. It approves grants of stock options, restricted shares units (RSUs) and deferred share units (DSUs) in accordance with the provisions of the respective plans. It reviews executive compensation disclosure prior to the Company releasing such information to the public.

It recommends executive officer appointments to the Board of Directors for approval. It ensures there is an adequate succession planning process for senior management and other potential senior management candidates of the Company and its affiliates and actively participates in that process with a review conducted on an annual basis. It reviews share ownership guidelines for executive officers. It ensures there are appropriate labour relation strategies in place and regularly reviews management's direction and decisions made in support of effectual labour and employee relations.

Officer Compensation

The Board of Directors determines the compensation for the Company's senior executives, including the Officers of the Company, on the recommendation of the Management Resources and Compensation Committee. See the section of this Circular entitled "Compensation Discussion & Analysis" above with respect to compensation of the Company's Named Executive Officers.

The Management Resources and Compensation Committee engaged Hugessen Consulting Inc. as a compensation consultant to assist in determining compensation for senior management, including the President. See "Compensation Advisors" above for more information about the engagement of compensation advisors.

Nominating and Corporate Governance Committee

The Nominating and Corporate Governance Committee assists the Board with matters relating to corporate governance. The Committee consists of independent Directors only, selected by the Board. The Committee identifies individuals qualified to become Directors who are, in the opinion of the Committee, able to contribute to the broad range of issues with which the Directors must deal and who are able to devote the time necessary to prepare for and attend meetings of the Board and Committees of the Board to which they may be appointed.

The Committee must ensure that not less than 25 percent of the members of the Board of Directors are female. The Committee is required to create and review the criteria for selecting Directors by assessing the personal qualities, business experience, and qualifications of current Directors, assess the Company's ongoing needs and circumstances, geographical representation and the overall experience of the Board.

Prior to each annual shareholders' meeting, the Committee must provide the Company with a list of nominees for election as Directors to be included in the Company's Management Information Circular for that meeting. The list of Director nominees must include the President and Chief Executive Officer of the Company. It may include one other senior executive of the Company, as determined by the Committee, but the President and Chief Executive Officer is the only Executive of the Company nominated for election at the annual shareholders meeting on May 5, 2010.

Director nominees must not be employees of the Company or of any subsidiary or affiliate of the Company and must not have reached 70 years of age, except in certain exceptional circumstances. The Committee may determine and recommend that an individual be permitted to serve as a Director beyond age 70 because of the individual's contribution and skills. Such determination will be made annually. One of the Directors nominated for election is 72 and the Committee has determined and recommended to the Board of Directors that because of that individual's unique and valuable contribution, that individual should continue to serve as a Director.

The Nominating and Corporate Governance Committee is responsible for assessing on an annual basis the effectiveness of the Board, individual Directors, and its various committees.

The Nominating and Corporate Governance Committee is responsible for developing and communicating the Company's approach to corporate governance issues, and reviews and approves Emera's disclosure of corporate governance practices.

The Committee keeps abreast of best governance practices in the industry and continually evaluates the governance practices of Emera.

Director Compensation

The Company is committed to attracting highly skilled and experienced Directors to serve on its Board and, therefore, strives to maintain appropriate and competitive compensation for Directors.

The Board of Directors determines the compensation for the Company's Directors on the recommendation of the Nominating and Corporate Governance Committee.

The Nominating and Corporate Governance Committee annually reviews the compensation of the Directors to ensure the form of compensation is appropriate. In doing so, the Committee carries out a review of the compensation practices of Canadian publicly-traded companies similar to Emera's operations and size and ensures the Directors are appropriately compensated for the responsibilities and risks involved in being a Director. The review is based upon publicly available information concerning Director's compensation, public surveys and comparison of compensation of Directors of publicly-traded companies in Canada.

In 2009, the Committee engaged Hugessen Consulting Inc. to review appropriate comparator groups for Emera, to review the level and form of Directors' compensation for such comparator groups, to review trends in level and form of Director compensation in Canada, and to provide recommendations on level and form of Director compensation.

January 1, 2010 Director Compensation Increase

Following a review of Director compensation, the Nominating and Corporate Governance Committee determined that effective January 1, 2010, the annual retainer for the Company's Directors shall be increased by $25,000 payable in the form of deferred share units (DSU) only. Other adjustments to Director compensation were also made. The changes in the compensation for Directors are summarized in the following table.

	Effective January 1, 2010	Previous Rates
Annual Chair's Retainer (all inclusive)	$80,000 – cash $80,000 – DSUs	$160,000 – cash
Annual Director Retainer	$35,000 – cash $25,000 – DSUs	$35,000 – cash
Annual Committee Chair Cash Retainers	$15,000 – Audit Chair $15,000 - MRCC Chair $8,000 - N&CGC Chair	$15,000 - Audit Chair $12,000 - MRCC Chair $5,000 N&CGC Chair
Annual Committee Member Cash Retainers (Not paid to Committee Chairs)	$5,000 Audit $3,000 MRCC $3,000 N&CGC	$5,000 Audit $3,000 MRCC $3,000 N&CGC

	Effective January 1, 2010	Previous Rates
In-Person Meeting Fee	$1,750	$1,750
Telephone Meeting Fee	$1,250	$1,250
Travel Fee	$ 1,750 if one-way travel is at five hours or more $875 if one-way travel is at least three hours but less than five hours	$1,750 if one-way travel is at five hours or more $875 if one-way travel is at least three hours but less than five hours

Director Share Ownership Guidelines

In order to align their interests with those of the Company's shareholders, the Directors are subject to share ownership guidelines. The original guidelines, which were implemented in July 2003, required each non-employee Director to own the equivalent of five times the annual Directors' retainer, then equal to 100,000, in common shares and/or DSUs within five years of becoming a Director. For Directors serving on the Board at the time the guidelines were established, compliance was to have occurred by July 2008.

In September 2008 the Directors amended the guidelines to require the preponderance of Directors to own five times the annual Director's retainer, then equal to $175,000, in common shares and/or DSUs within five years of the new ownership guideline coming into effect (ie. by September 2013) or five years from the appointment date of a new Director.

New Share Ownership Guidelines

The share ownership guidelines for Directors of the Company were further amended in September 2009, such that effective January 1, 2010 all Directors must each own three times the new total cash and equity-based annual Board retainer for Directors, equal to $180,000. Under this amended guideline, each and every Director must own Emera shares or DSUs, or a combination of the two, worth $180,000 by the earlier of either September 2013 (in accordance with the September 2008 amendment) or within five years of the appointment date of a new Director.

Details of each Director's share and DSU ownership, and status under the share ownership guidelines, is shown in each nominee Director's biography earlier in this Circular.

As a result of increasing Director compensation by $25,000 payable in DSUs only, which are only payable on retirement from the Board, the Directors will increase their shares or share based ownership by at least $25,000 per annum.

Board and Director Performance Assessments

The Board recognizes the value of regularly assessing its effectiveness in order to find ways to improve its performance and the performance of the Chair, individual Directors, and the Board Committees. In February 2009, the Board of Directors adopted a guideline for the performance of assessments of the effectiveness of the Board of Directors, its committees, an assessment of the Chair of the Board.

Assessment Process

Under the guideline, each year the Nominating and Corporate Governance Committee determines the process by which Director performance assessments will be conducted. The process may include the use of questionnaires, one-on-one interviews with Directors by the Board Chair or such other process as the Committee determines appropriate. A report on the assessment is provided to the Board of Directors. Issues arising from the assessment are identified, an action plan developed and progress monitored by the Nominating and Corporate Governance Committee.

2009 Board/Director Performance Assessment

In December 2009, the Chair of the Board spoke to each external Emera Director as part of the 2009 Board and Director Performance Assessment. A series of questions was sent to each Director in advance for their consideration on a number of themes, including the operation and effectiveness of the Board of Directors, the operation of Committees, and the performance of Directors themselves. The Chair summarized the main points in a written report and provided the Nominating and Corporate Governance

Committee and the Board with further detail about the comments he received in order to discuss the comments with all Directors.

The assessment of the Chair of the Board was conducted in a meeting of all Directors that was led by the Chair of the Nominating and Corporate Governance which excluded the Board Chair.

The Nominating and Corporate Governance Committee received the findings and the results of the 2009 Board and Director Performance Assessment. The Chair worked to develop an action plan based on those findings where necessary. That action plan was shared with the Board, and progress on the action plan will be reported to the Committee and the Board from time to time.

Strategic Planning

The Board regards the shaping of the Company's strategy as one of its primary roles. Directors participate in the development of the corporate strategy which determines the annual and longer-term objectives for the President and Chief Executive Officer. The Directors regularly evaluate progress made in pursuing that strategy.

Plan Development

The Chief Executive Officer, in collaboration with Executive Officers and the Board of Directors, develops a strategic plan which is presented to the Directors at a mid-year strategic retreat for approval. Management engages the Directors in "blue sky" sessions in the first half of the year as a prelude to formal annual strategic planning exercise.

Business Plan and Corporate Scorecard

The strategic plan is translated into a business plan which is presented for Board approval in the second half of the year.

The Company has adopted the Scorecard approach to translate corporate strategies into measurable incentive plan goals and the President and Chief Executive Officer's performance for the year is measured against the Scorecard.

Corporate objectives for the President are established on an annual basis and are based on the strategy, are reviewed by the Management Resources and Compensation Committee, and are approved by the Board of Directors.

Communications with Directors

Shareholders may communicate with the Chair of the Board or other independent Directors as a group by mailing (by regular mail or other means of delivery) to the corporate head office at 18th Floor, 1894 Barrington Street, Barrington Tower, Halifax, N.S., B3J 2A8, in a sealed envelope marked "Private and Confidential – Attention Chair of the Board of Directors of Emera Incorporated".

Additional Information

Additional information relating to the Company may be found on SEDAR at www.sedar.com. The Company's financial information is contained in its comparative financial statements and Management's Discussion and Analysis ("MD&A") for the financial year ended December 31, 2009.

For copies of the Company's financial statements and MD&A, you may also contact the Office of the Corporate Secretary at 1894 Barrington Street, Suite 1800, Barrington Tower, P.O. Box 910, Halifax, Nova Scotia, B3J 2W5. Telephone: (902) 428-6096; Facsimile: (902) 428-6171.

Appendix A

EMERA INCORPORATED
CHAIR OF THE BOARD OF DIRECTORS
MANDATE

Responsibility

The fundamental responsibility of the Chair of the Board of Directors (the "Chair") of the Company is to lead the Board to fulfill its duties effectively, efficiently and independent of Management. The Chair provides leadership to the Board in reviewing and deciding upon matters which exert major influence on the manner in which the Company's business is conducted and ensure effective operation of the Board. The Chair acts in a general advisory capacity to the President and Chief Executive Officer and other officers in all matters concerning the interests and management of the Company.

Independence

The Chair shall be an independent Director in accordance with the Company's Articles of Association and applicable legislation.

Specifically, the Chair shall perform the duties as required in the Company's Articles of Association and shall:

Meetings

1. Ensure the Board is properly organized, functions effectively and meets its obligations and responsibilities including those relating to corporate governance matters.

2. Preside at and manage Board meetings and shareholder meetings.

3. Plan and organize the activities of the Board in consultation with the Chief Executive Officer and Corporate Secretary.

4. Ensure proper flow of information to the Board to support decision making and to allow adequate lead time for effective study and discussion of business under consideration.

5. Review and provide input to meeting agendas and ensure sufficient time during Board meetings to fully discuss agenda items.

Leadership

6. Counsel collectively and individually with members of the Board, utilizing their capacities to the fullest extent necessary to optimize the effectiveness of the Board and its Committees.

7. Ensure delegated Committee functions are carried out and reported to the Board.

8. Provide the Board, Committees and individual Directors with leadership to assist them in their duties and responsibilities, and actively participate in the selection of Committee members and Committee Chairs.

9. Provide advice, counsel and mentorship to individual Directors, to assist them to improve performance or, when appropriate, to transition them from the Board.

Board Management Relationship

10. Ensure that the boundaries between Board and Management responsibilities are clearly understood and respected and that relationships between the Board and Management are conducted in a professional and constructive manner.

11. Facilitate effective communication between Directors and Management, both inside and outside of Board meetings.

12. Ensure the Board can function independently of management and that the independent Directors have adequate and regularly scheduled opportunities to meet to discuss issues without Management present.

13. Act as the principal liaison between the Board and management working closely with the Chief Executive Officer to ensure management strategies, plans and performance are appropriately represented to the Board.

Director Recruitment, Retention, Education

14. With the Nominating and Corporate Governance Committee, actively participate in the recruitment and retention of Directors.

15. Support the orientation of new Directors and the continuing education of existing Directors.

Assessment/Evaluation

16. In conjunction with the Board's Nominating and Corporate Governance Committee, ensure a process is in place to assess the effectiveness of the overall Board and its members.

17. Assess, in conjunction with the Management Resources and Compensation Committee, the performance of the Chief Executive Officer and provide input with respect to compensation and succession.

Other

18. At the request of the Chief Executive Officer, or where appropriate, represent the Board at official functions and meetings with major shareholder groups and other stakeholder groups.

19. Carry out any other appropriate duties and responsibilities assigned by the Board.

Appendix B

EMERA INCORPORATED
BOARD OF DIRECTORS CHARTER

The fundamental responsibility of the Board of Directors (the "Board") is to provide stewardship and governance to Emera to ensure the viability of the company by overseeing management of the business. In addition to the powers set out in Emera's Articles of Association, the Board shall have the following duties and responsibilities.

Management of Business

1. The management of the business of Emera shall be vested in the Directors pursuant to the Articles of Association.

2. The Board shall appoint executive officers, delegate the necessary authority for the conduct of the business thereto, evaluate the performance, and approve compensation for executive officers.

3. The Board shall adopt a strategic planning process resulting in a strategic plan which shall be approved on an annual basis and shall take into account, among other things, the opportunities and risks of the business.

4. The Board shall review and approve all material acquisitions, dispositions, projects, business plans, and budgets.

Financial and Risk Responsibility

5. The Board shall ensure that appropriate systems are implemented to identify, report, and manage budgets.

6. The Board will review the financial performance of the Company, declare dividends as appropriate, and approve financial results for release to the public as necessary.

7. The Board shall review and ensure the quality and integrity of Emera's internal controls and management information systems.

Governance Responsibility

8. The Board shall perform such duties and approve certain matters as may be required by applicable legislation and the Articles of Association.

9. The Board shall be comprised of a number of Directors as set out in Emera's Articles of Association.

10. Pursuant to the Articles, the Directors shall appoint one of the Directors as Chair of the Board and such Director shall not be an employee of Emera or any of its affiliates or subsidiaries.

11. The Board, in carrying out its mandate, shall appoint committees of the Board and delegate certain function to those committees, each of which shall have its own written charter.

12. The Board shall ensure that Emera has a formal corporate disclosure policy and a program to receive feedback from shareholders.

13. The Board shall establish a system of corporate governance appropriate for Emera which includes practices to ensure that the Board functions independent of management and in the interests of its shareholders, has a process for the selection of qualified individuals for board nomination, and the evaluation and compensation of Directors.

Independence and Integrity

14. The Board shall be comprised of a majority of independent Directors as required by applicable legislation.

15. The Chair shall be independent as required by applicable legislation.

16. The Board shall ensure the Emera has a business code of ethical business conduct and a procedure to ensure that it is adhered to throughout the Company.

17. The Board shall satisfy itself as to the integrity of the Chief Executive Officer and executive officers and the creation of an integrity-based culture throughout the Company.

18. The Board shall, through its oversight of management, continue to foster an organization which operates in an environmentally responsible manner.

Requirement:

Applicable emissions targets legislated and compliance accomplished for past year and current year, and how compliance is planned for the test year and five years into the future.

Submission:

NS Power is required to manage air emissions within annual limits regulated by Nova Scotia Environment. Table 1 shows established annual air emission limits to year 2020, including percentage renewable targets in the Renewable Electricity Standard (RES).

Table 1

<table>
<tr><th>Year</th><th>SO_2 tonnes</th><th>NO_X tonnes</th><th>Mercury kg</th><th>GHGs Mtonnes</th><th>RES %</th></tr>
<tr><td>2010</td><td>72,500</td><td>21,365</td><td>110</td><td rowspan="2">19.22</td><td rowspan="2">5</td></tr>
<tr><td>2011</td><td>72,500</td><td>21,365</td><td>100</td></tr>
<tr><td>2012</td><td>72,500</td><td>21,365</td><td>100</td><td rowspan="2">18.50</td><td rowspan="2">10</td></tr>
<tr><td>2013</td><td>72,500</td><td>21,365</td><td>85</td></tr>
<tr><td>2014</td><td>72,500</td><td>21,365</td><td>65</td><td rowspan="3">26.32</td><td rowspan="2">25</td></tr>
<tr><td>2015</td><td>60,900</td><td>19,228</td><td>65</td></tr>
<tr><td>2016</td><td>60,900</td><td>19,228</td><td>65</td><td rowspan="5">40*</td></tr>
<tr><td>2017</td><td>60,900</td><td>19,228</td><td>65</td><td rowspan="3">24.06</td></tr>
<tr><td>2018</td><td>60,900</td><td>19,228</td><td>65</td></tr>
<tr><td>2019</td><td>60,900</td><td>19,228</td><td>65</td></tr>
<tr><td>2020</td><td>36,250</td><td>14,955</td><td>35</td><td>7.50</td></tr>
</table>

* Note – The RES limit for 2020 has been announced but is not yet in the RES regulations.

For 2013 and 2014, the cap on annual air emissions for sulphur dioxide (SO_2) is 72,500 tonnes. The cap for the SO_2 will remain at 72,500 tonnes until 2015 and the cap for annual emissions of nitrogen oxides (NO_x) is 21,365 tonnes. The cap on annual emissions of mercury was originally 65 kg for each calendar year out to 2019 and then 35 kg by year 2020. However, an announcement by the Provincial Government in July, 2010 deferred the 65 kg emission cap until 2014, and for calendar years 2010, 2011, 2012 and 2013, annual emission limits became 110 kg; 100 kg; 100 kg and 85 kg respectively. Further, if the annual emissions of mercury exceed 65 kg in any of years 2010 to 2013, the total excess emissions above 65 must be compensated for by reducing annual emissions to a level below 65 kg so that the total reduced emissions equals or exceeds the excess emissions above 65 kg by year 2020. Additionally, 2010 marked the first year of the initial 2 year Compliance Period for which NS Power was required to meet an emission limit for greenhouse gas (GHG) with a limit of 19.22 million MT. The GHG emission limit will be 18,500,000 tonnes in the 2012-2013 Compliance Period and then moving to a three-year total compliance period limit for 2014 to 2016 of 26,320,000 tonnes.

NS Power manages its actual air emissions to meet these emissions caps by:

- purchasing and combusting specific quality fuels
- increasing production from renewable energy sources
- procuring power from other sources (imported power and Independent Power Producers)
- managing the load through energy conservation and efficiency programs, and
- in select cases by installing emission control equipment as discussed further below

In 2006, the first Low NO_x Combustion Firing System (LNCFS) was installed, at Lingan 3. In 2007, two additional units (Lingan 2 and 4) were fitted with LNCFS. In 2008, three additional units (Lingan 1, Pt. Tupper 2 and Trenton 6) were fitted with LNCFS. The seven LNCFS units installed will enable NS Power to continue to meet the NO_x emission cap of 21,365 tonnes up to 2015.

In late 2009, NS Power installed mercury abatement equipment on seven of its solid fuel generating units to comply with the reduced mercury cap. The mercury abatement equipment consists of front-end chemical additives applied to the fuel prior to combustion and activated carbon injection (ACI) upstream of the particulate control device. The mercury abatement equipment has been tested with the solid fuel units using different fuel blends to characterize retention of mercury in ash.

In addition to these fleet-wide caps, each generating facility operates within a permit which requires ground level ambient air quality to be maintained, plume visibility to be within limits and, in some cases, specific emission standards to be met.

Requirement:

Quantities and classes of shares, and price as of filing.

Submission:

NS Power

As of December 31, 2011 NS Power had 117.2 million issued and outstanding common shares. The shares are not publicly traded.

As of December 31, 2011 NS Power had 5.4 million 5.9 percent Series D First Preferred Share Units.

As of April 24, 2012 the Series D preferred shares were trading at $27.53.

Emera

As of December 31, 2011 Emera had 122.8 million issued and outstanding common shares. As of April 24, 2012 the shares were trading at $34.30.