Management's Discussion & Analysis

As at February 8, 2013

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 2012 relative to 2011; and the full year of 2012 relative to 2011 and 2010; and its financial position as at December 31, 2012 relative to December 31, 2011. 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.

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, 2012. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP").

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 Commission ("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 and the Caribbean Utility Operations sections of the MD&A, which are 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.

Forward-Looking Information

This MD&A contains “forward-looking information” within the meaning of applicable Canadian securities laws. 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 risk; 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 and Balance Sheets and outstanding common stock data; then presents information separately on Emera's consolidated subsidiaries and investments, specifically:

- NSPI;
- Maine Utility Operations includes Bangor Hydro and MPS;
- Caribbean Utility Operations includes BLPC and its parent company, Light & Power Holdings Ltd. ("LPH"), GBPC and St. Lucia Electricity Services Limited ("Lucelec");
- Pipelines includes Brunswick Pipeline and Maritimes & Northeast Pipeline ("M&NP");
- Other operations and investments are grouped and discussed under Services, Renewables and Other Investments and include:
    - Emera Energy includes Emera Energy Services, Bayside Power Limited Partnership ("Bayside Power"), Bear Swamp Power Company LLC. ("Bear Swamp") and Northeast Wind Partners II, LLC ("NWP"),
    - Emera Utility Services Inc. and Emera Utility Services (Bahamas) Limited ("Utility Services"),
    - Emera Newfoundland & Labrador Holdings Inc. ("ENL"),
    - Algonquin Power & Utilities Corp. ("APUC"),
    - Atlantic Hydrogen Inc. ("AHI"),
    - Open Hydro Group Limited ("Open Hydro"); and
- Corporate includes interest revenue on intercompany financings and costs associated with corporate activities not directly associated with the operations of Emera's consolidated subsidiaries and investments noted above.

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

INTRODUCTION AND STRATEGIC OVERVIEW

Emera Incorporated is an energy and services company that owns and invests in electricity generation, transmission and distribution, gas transmission, utility services and provides energy marketing, trading and other energy-related management services.

Emera's strategy is focused on driving profitable growth by investing in its existing and new businesses, improving the reliability and cost of service, reducing emissions from the generation of electricity, and transmitting that cleaner energy to market. Emera continues to build its existing businesses and leverage its core strength in utilities to pursue acquisitions and greenfield development opportunities in electric or gas utilities in addition to assets active in electricity, generation and energy-related services.

Emera's business interests are primarily in northeastern North America and the Caribbean. Approximately 80 percent of Emera's net income is earned by its rate-regulated subsidiaries, which generally contribute strong, predictable income and cash flows to fund dividends and reinvestment.

The energy industry is seasonal in nature for companies like Emera, where seasonal and unseasonal weather patterns can affect the demand for energy and the cost of service. Similarly, mark-to-market adjustments arising from commodity purchases or trading activities that do not qualify for hedge accounting or regulatory accounting can have a material impact on financial results for a period.

Therefore, results in any one quarter are not necessarily indicative of results in any other quarter, or for the year as a whole.

Non-GAAP Financial Measures

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

Electric Margin

NSPI

"Electric margin" is a non-GAAP financial measure used to show the amounts NSPI retains to recover its non-fuel operating costs, as effectively all fuel costs flow through the fuel adjustment mechanism ("FAM"). NSPI's electric margin may not be comparable to other companies' electric margin measures. This measure is not intended to replace "Income from operations" which, as determined in accordance with GAAP, is an indicator of operating performance. Electric margin is discussed further in the NSPI – Electric Margin section.

Electric margin is summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
	2012	2011	**2012**	2011	2010
Operating revenues – regulated	**$ 324.8**	$ 289.2	**$ 1,237.2**	$ 1,233.0	$ 1,191.4
Less: Other revenues	**(8.1)**	(6.3)	**(26.8)**	(23.3)	(24.1)
Total electric revenues	**316.7**	282.9	**1,210.4**	1,209.7	1,167.3
Total electric revenues is broken down as follows:					
Fuel electric revenues – current year	**$ 128.5**	$ 115.6	**$ 481.2**	$ 512.6	$ 513.7
Fuel electric revenues – preceding years	**16.7**	6.1	**65.9**	26.6	(22.4)
Non-fuel electric revenues	**171.5**	161.2	**663.3**	670.5	676.0
Total electric revenues	**316.7**	282.9	**1,210.4**	1,209.7	1,167.3
Regulated fuel for generation and purchased power	**(135.9)**	(127.8)	**(494.9)**	(547.4)	(586.7)
Regulated fuel adjustment	**(13.3)**	4.5	**(54.7)**	8.5	99.0
Regulated fixed cost adjustment	**11.3**	-	**44.7**	-	-
Fuel-related foreign exchange and other fuel-related costs (1)	**(0.3)**	(1.4)	**(1.8)**	(7.4)	(9.3)
Electric margin	**$ 178.5**	$ 158.2	**$ 703.7**	$ 663.4	$ 670.3

(1) As reported in "Other income (expense) net", "Depreciation and amortization", and "Interest expense, net" on the Consolidated Statements of Income.

Caribbean Utility Operations

"Electric margin" is a non-GAAP financial measure used by Caribbean Utility Operations to show the amounts it retains to recover its non-fuel operating costs. Caribbean Utility Operations' electric margin may not be comparable to other companies' electric margin measures. This measure is not intended to replace "Income from operations" which, as determined in accordance with GAAP, is an indicator of operating performance. Electric margin is discussed further in the Caribbean Utility Operations – Electric Margin section.

Emera acquired a controlling interest in LPH and GBPC on January 25, 2011 and December 22, 2010 respectively. Thus, there are no 2010 comparative figures in the table below.

Electric margin is summarized in the following table:

For the millions of US dollars		Three months ended December 31			Year ended December 31
		2012	2011	**2012**	2011
Operating revenues – regulated	**$**	**101.3**	$ 105.6	**$ 421.1**	$ 411.2
Less: Other revenues		**(0.9)**	(0.8)	**(2.9)**	(3.0)
Total electric revenues		**100.4**	104.8	**418.2**	408.2
Total electric revenues is broken down as follows:					
Electric revenues – base rate	**$**	**38.9**	$ 36.8	**$ 157.6**	$ 148.9
Fuel charge		**61.5**	68.0	**260.6**	259.3
Total electric revenues		**100.4**	104.8	**418.2**	408.2
Regulated fuel for generation and purchased power (1)		**61.5**	71.7	**264.8**	276.9
Regulatory amortization (2)		**0.7**	(1.0)	**1.8**	(4.4)
Electric margin	**$**	**38.2**	$ 34.1	**$ 151.6**	$ 135.7

(1) In Q4 2012, regulated fuel for generation and purchased power includes $ nil (2011 – $3.1 million) of temporary generation costs. For the year ended December 31, 2012, regulated fuel for generation and purchased power includes $3.7 million (2011 – $10.1 million) of temporary generation costs.
(2) Included in "Depreciation and amortization" on the Consolidated Statements of Income

Mark-to-Market Adjustments

"Adjusted net income attributable to common shareholders", "adjusted earnings per common share – basic", "adjusted contribution to consolidated net income" and "adjusted contribution to consolidated earnings per common share – basic" are non-GAAP financial measures used by Emera. These measures represent net income and non-diluted earnings per common share absent the income effect of mark-to-market adjustments related to Emera's held-for-trading ("HFT") derivative instruments and the mark-to-market adjustments included in Emera's equity income related to the business activities of Bear Swamp and NWP. HFT derivatives do not qualify for hedge accounting or regulatory accounting. They are recognized on the balance sheet at fair value and all gains or losses are recognized in net income of the period.

Emera's HFT derivatives are primarily contracts related to the expected purchase and/or supply of electricity and natural gas which fluctuate in value due to market price volatility of the relevant commodity. Management believes excluding the effect of mark-to-market valuations, and changes thereto, related to these contracts from income until settlement better matches the financial effect of these contracts with the underlying cash flows and that presentation of adjusted net income attributable to common shareholders, adjusted earnings per common shareholders – basic, adjusted contribution to consolidated income and adjusted contribution to consolidated earnings per common share – basic provides useful information to investors as it allows them an additional relevant comparison of the Company's performance across reporting periods.

The most directly comparable USGAAP measure for adjusted net income attributable to common shareholders, adjusted earnings per common share – basic, adjusted contribution to consolidated net income and adjusted contribution to consolidated earnings per common share – basic is net income attributable to common shareholders, earnings per common share – basic, contribution to consolidated net income and contribution to consolidated earnings per common share, respectively. Mark-to-market adjustments are discussed further in the Consolidated Financial Highlights section and the Services, Renewables and Other Investments – Review of 2012 section.

The following is a reconciliation of reported net income attributable to common shareholders to adjusted net income attributable to common shareholders and reported earnings per common share – basic to adjusted earnings per common share – basic.

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2012	2011	**2012**	2011	2010
Net income attributable to common shareholders	**$ 42.7**	$ 46.8	**$ 220.8**	$ 241.1	$ 190.7
After-tax derivative mark-to-market gain (loss)	**$ (15.9)**	$ (0.9)	**$ (9.7)**	$ (3.0)	$ (3.2)
Adjusted net income attributable to common shareholders	**$ 58.6**	$ 47.7	**$ 230.5**	$ 244.1	$ 193.9
Earnings per common share – basic	**$ 0.34**	$ 0.38	**$ 1.77**	$ 1.99	$ 1.67
Adjusted earnings per common share – basic	**$ 0.46**	$ 0.39	**$ 1.85**	$ 2.02	$ 1.70

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		
	2012	2011	**2012**	2011	2010
Operating revenues	**$ 512.9**	$ 512.0	**$ 2,058.6**	$ 2,064.4	$ 1,606.1
Net income attributable to common shareholders	**42.7**	46.8	**220.8**	241.1	190.7
Earnings per common share – basic	**$ 0.34**	$ 0.38	**$ 1.77**	$ 1.99	$ 1.67
Earnings per common share – diluted	**$ 0.34**	$ 0.38	**$ 1.76**	$ 1.97	$ 1.65
Dividends per common share declared	**$ -**	$ -	**$ 1.3625**	$ 1.3125	$ 1.1625

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
Operating Unit Contributions (after-tax)	**2012**	2011	**2012**	2011	2010
NSPI	**$ 27.0**	$ 22.2	**$ 126.0**	$ 123.5	$ 119.2
Maine Utility Operations	**8.6**	9.8	**35.4**	37.0	31.9
Caribbean Utility Operations	**6.7**	3.1	**23.2**	46.8	19.8
Pipelines	**7.0**	6.9	**27.9**	27.9	28.9
Services, Renewables and Other Investments	**(2.4)**	5.4	**33.7**	26.4	8.6
Corporate	**(4.2)**	(0.6)	**(25.4)**	(20.5)	(17.7)
Net income attributable to common shareholders	**$ 42.7**	$ 46.8	**$ 220.8**	$ 241.1	$ 190.7
Adjusted net income attributable to common shareholders	**$ 58.6**	$ 47.7	**$ 230.5**	$ 244.1	$ 193.9
Earnings per common share – basic	**$ 0.34**	$ 0.38	**$ 1.77**	$ 1.99	$ 1.67
Adjusted earnings per common share – basic	**$ 0.46**	$ 0.39	**$ 1.85**	$ 2.02	$ 1.70

As at	December 31		
	2012	2011	2010
Total assets	**$ 7,527.2**	$ 6,923.6	$ 6,079.0
Total long-term liabilities	**4,250.4**	4,298.2	3,941.7

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 – 2010		**$ 190.7**
NSPI		4.3
Maine Utility Operations		5.1
Caribbean Utility Operations		27.0
Pipelines		(1.0)
Services, Renewables and Other Investments		17.8
Corporate		(2.8)
Consolidated net income attributable to common shareholders – 2011	**$ 46.8**	**$ 241.1**
NSPI	4.8	2.5
Maine Utility Operations	(1.2)	(1.6)
Caribbean Utility Operations	3.6	(23.6)
Pipelines	0.1	-
Services, Renewables and Other Investments	(7.8)	7.3
Corporate	(3.6)	(4.9)
Consolidated net income attributable to common shareholders – 2012	**$ 42.7**	**$ 220.8**

Developments

Emera

Progress on Muskrat Falls Projects

On July 31, 2012, Emera and Nalcor Energy ("Nalcor"), along with the Governments of Nova Scotia and Newfoundland and Labrador, executed 13 agreements pertaining to the development and transmission of hydroelectric power from Muskrat Falls, on the Churchill River in Labrador, to the island of Newfoundland, the Province of Nova Scotia and through to New England. The agreements relate to the development of a hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador ("Muskrat Falls Generating Station"), an electricity transmission project in Labrador between Muskrat Falls and Churchill Falls ("Labrador Transmission Assets"), an electricity transmission project in Newfoundland and Labrador to enable the movement of the Muskrat Falls energy between Labrador and the island of Newfoundland ("the Labrador-Island Transmission Link") and a transmission project between the island of Newfoundland and Nova Scotia, including a 180-kilometre subsea cable ("Maritime Link Project").

The execution of these agreements was followed, on November 30, 2012, with a finalization of the Federal Loan Guarantee term sheet between the Governments of Canada, Nova Scotia and Newfoundland and Labrador, as well as Nalcor and Emera. The Federal Loan Guarantee provides that the Government of Canada will fulfill any payment obligations relating to the Maritime Link in the event of a default on the guaranteed debt. This guarantee enhances the credit rating to that of the Government of Canada, thus providing a material reduction to the cost of borrowing for the Maritime Link Project.

On December 5, 2012, the Newfoundland and Labrador legislature voted in favour of a bill to approve the Muskrat Falls Generating Station, the Labrador Transmission Assets and the Labrador-Island Transmission Link projects.

On December 17, 2012, Emera and Nalcor entered into a sanction agreement enabling both parties to advance their respective projects. Nalcor officially sanctioned the Muskrat Falls Generating Station and the Labrador-Island Transmission Link projects on December 17, 2012, and at that time revised and finalized its capital cost estimates for the Muskrat Falls Generating Station including Labrador Transmission Assets from $2.9 billion to $3.6 billion and from $2.1 billion to $2.6 billion for the Labrador-

Island Transmission Link. This now sets the stage for construction to begin on the Nalcor projects. On behalf of Emera, ENL's two subsidiaries, NSP Maritime Link Inc. and ENL Island Link Inc. will respectively carry out the development of the Maritime Link Project and invest in the Labrador-Island Transmission Link Project.

On January 28, 2013, NSP Maritime Link Inc. filed an application with the UARB seeking approval of the Maritime Link Project. Emera will make its final construction decision on the Maritime Link Project in late 2013, following the UARB decision.

Common Share Financing

On December 14, 2012, Emera completed an offering of 5,905,250 common shares, including the exercise of the over-allotment option of 770,250 common shares, at $34.10 per common share, for gross proceeds of $201.4 million and net proceeds of $193.2 million. The proceeds of the offering will be used primarily to fund the acquisition of Emera's interests in NWP, additional investments in APUC and development costs incurred in connection with the Maritime Link Project.

Brooklyn Power Corporation

On December 11, 2012, Emera signed an agreement with the Government of Nova Scotia to acquire Brooklyn Power Corporation ("Brooklyn Energy"), which owns a 30-megawatt ("MW") biomass co-generation facility located in Brooklyn, Nova Scotia for $25 million. The transaction is expected to close in the first half of 2013 and will be financed through existing credit facilities. Brooklyn Energy has a long-term power purchase agreement with NSPI.

Increase in Common Share Dividend

On September 28, 2012, Emera's Board of Directors approved an increase in the annual common share dividend rate from $1.35 to $1.40, and accordingly declared a quarterly dividend of $0.35 per common share.

Strategic Investment Agreement with Algonquin Power & Utilities Corp.

Emera's Strategic Investment Agreement ("SIA") with Algonquin Power & Utilities Corp ("APUC"), establishes how Emera and APUC will work together to pursue specific strategic investments of mutual benefit. The SIA also provides for Emera to acquire up to 25 percent of APUC through the purchase of common shares issued by APUC to fund certain investment opportunities under the SIA. The acquisition of APUC shares is subject to regulatory approval.

On June 25, 2012, Emera requested FERC and MPUC approval to increase its ownership in APUC to 25 percent; these approvals have now been received. The MPUC order, received on January 28, 2013, gave approval of Emera's 25 percent ownership interest in APUC and stipulated that Emera's dollar investment in APUC cannot exceed 5 percent of Emera's total assets. As at December 31, 2012, Emera's APUC investment comprised 3.1 percent of Emera's total assets. Emera's ownership in APUC, as well as its ownership in NWP, is currently under appeal to the Maine Supreme Court, and a decision is expected in 2013.

APUC share purchases are made through the acquisition of subscription receipts in exchange for promissory notes at an agreed upon price, which are exchangeable into common shares upon meeting certain transaction specific conditions, or at a later date at Emera's option, as applicable. The acquisition and conversion of subscription receipts is subject to approvals required under applicable laws, including the rules of the Toronto Stock Exchange ("TSX"). The pre-tax gains are recorded in "Other income (expenses), net" on Emera's Consolidated Statements of Income.

Emera owned 34.9 million common shares of APUC as at December 31, 2012 as outlined below:

Underlying Transaction	Number of Shares /Subscription Receipts	Price per Subscription Receipt	Closed or Expected to Close	Ownership in APUC – Actual and Pro forma
Acquisition of California Pacific	8,523,000	$3.25	Closed in Q1 2011	6%
New Hampshire Transaction	12,000,000	$5.00	Closed in Q2 2012	13%
Gamesa – ½ of first tranche	2,614,006	$5.74	Closed in Q3 2012	14%
Atmos	6,976,744	$6.45	Closed in Q3 2012	18%
Sale of CPUV – first tranche	4,790,000	$4.72	Closed in Q4 2012	20%
Gamesa –½ of first tranche	2,614,005	$5.74	Closed in Q1 2013	20%
Gamesa – second tranche	5,228,011	$5.74	Expected to close in Q1 2013	22% (2)
Completion of California Pacific's rate case – second tranche	3,421,000	$4.72	Expected to close in Q1 2013	23%(2)

(1) As at December 31, 2012, Emera's ownership interest in APUC was 18.5% as a result of dilutive equity transactions in late Q4 2012.

(2) The percentages are pro-forma assuming no other shares or other dilutive instruments are issued by APUC.

California Pacific Utility Ventures LLC (“CPUV”) Transaction

In April 2011, Emera agreed to sell its 49.999 percent direct ownership in CPUV, the parent of California Pacific Electric Company LLC (“California Pacific”) to APUC for $38.8 million, subject to applicable regulatory approval. Related to this agreement, Emera purchased 8.2 million subscription receipts from APUC at an issue price of $4.72 each for a total purchase price of $38.8 million.

On December 21, 2012, Emera sold its direct ownership in CPUV, which resulted in an after-tax gain on sale of $2.2 million. The pre-tax gain of $3.6 million was recorded in Q4 2012 in Other income (expenses), net on Emera’s Consolidated Statements of Income.

On December 27, 2012, subsequent to receiving all appropriate regulatory approvals surrounding the sale of Emera’s direct ownership interest in CPUV to APUC, Emera paid the promissory note and converted the subscription receipts into 4.8 million APUC shares, increasing its interest to 19.9 percent. This resulted in an after-tax gain of $8.4 million being recorded in Q4 2012.

Gamesa Transaction

On June 28, 2012, Emera purchased 10.5 million subscription receipts from APUC at an issue price of $5.74 each for a total purchase price of $60.0 million in connection with APUC’s agreement with Gamesa Corporaciãn Tecnolãgica, S.A. (“Gamesa”) to acquire a portfolio of wind power projects in the United States and to jointly pursue additional wind power development opportunities.

On July 12, 2012, Emera paid $15 million of the promissory note and converted 2.6 million of the subscription receipts into APUC common shares increasing its interest in APUC to approximately 14 percent. This resulted in an after-tax gain of $1.8 million being recorded in Q3 2012.

On December 11, 2012, Emera paid the remaining $45 million of the promissory note making the remaining 7.8 million subscription receipts convertible at the election of Emera into APUC common shares.

On February 6, 2013, Emera converted 2.6 million subscription receipts into 2.6 million APUC shares, increasing its interest in APUC to approximately 19.6 percent. This resulted in an after-tax gain of $3.6 million being recorded in Q1 2013.

Atmos Transaction

On July 27, 2012, Emera purchased 6.977 million subscription receipts from APUC at an issue price of $6.45 each for a total purchase price of $45.0 million in connection with APUC's acquisition of certain regulated natural gas distribution utility assets of Atmos Energy Corporation ("Atmos").

On July 31, 2012, Emera paid the promissory note and converted the 6.977 million subscription receipts into 6.977 million APUC common shares, increasing its interest in APUC to approximately 18 percent. This resulted in an after-tax gain of $0.9 million being recorded in Q3 2012.

New Hampshire Transaction

In March 2011, Emera acquired 12 million subscription receipts from APUC at an issue price of $5.00 each for a total purchase price of $60.0 million related to the acquisition by APUC's regulated subsidiary of all issued and outstanding shares of Granite State Electric Company and Energy North Natural Gas Inc.

On May 14, 2012, Emera paid the promissory note and converted 12 million subscription receipts into 12 million APUC common shares, increasing its interest in APUC to approximately 13 percent. This resulted in an after-tax gain of $11.6 million being recorded in Q2 2012.

Emera's Partnership with First Wind Holdings LLC

On June 15, 2012, Emera and First Wind Holdings LLC ("First Wind") closed their transaction to jointly own and operate 385 MW of wind energy projects in the northeastern United States through a new company, NWP, owned 51 percent by First Wind, and 49 percent by Emera. First Wind serves as the managing partner and will continue to operate the wind energy projects. Emera Energy Services will provide energy management services to NWP. Emera invested $219 million ($215 million USD), including transaction costs, for its 49 percent interest and loaned $152.9 million ($150 million USD) to NWP, to be repaid in five years. Emera financed this transaction through existing credit facilities.

On April 30, 2012, an MPUC order approved the First Wind transaction. Emera's ownership in NWP has been appealed to the Maine Supreme Court, and a decision is expected in 2013.

At the closing of the First Wind Transaction, Emera and First Wind entered into an agreement relating to additional wind energy projects developed or acquired by First Wind. Upon a wind energy project(s) meeting certain financial and non-financial conditions, Emera will purchase a 49 percent interest in the wind energy project(s).

US Securities and Exchange Commission Registration Termination

On March 20, 2012, Emera filed with the United Stated Securities and Exchange Commission ("SEC") a post-effective amendment to its Form F-9 registration statement removing from registration its debt securities, first preferred shares and second preferred shares.

On June 21, 2012, Emera filed with the SEC to remove its common shares from registration and filed to terminate its reporting obligations under Section 15(d) of the United States Securities Exchange Act of 1934, as amended in respect of its common shares, first preferred shares and debt securities. On September 20, 2012, the SEC review period expired and Emera's reporting obligations in respect of its common shares, first preferred shares and debt securities terminated under United States securities laws. Emera will continue to report its financial results in accordance with USGAAP, as approved by Canadian securities regulators.

Preferred Share Issuance

On June 7 2012, Emera issued ten million 4.10 percent Cumulative Six-Year Rate Reset First Preferred Shares, Series C ("First Preferred Shares, Series C"). The First Preferred Shares, Series C were issued at $25.00 per share for gross proceeds of $250.0 million and net proceeds of $244.9 million. The net proceeds of the share offering were used to repay short-term borrowings and for general corporate purposes.

NSPI

Regulatory Filings

2013 General Rate Application Settlement

On May 8, 2012, NSPI filed a General Rate Application ("GRA") for 2013 and 2014 with the UARB. In an effort to smooth rate increases, NSPI requested the UARB approve an average net 3 percent increase in rates effective January 1, 2013 and again on January 1, 2014, and for those years to continue in part, a deferral mechanism similar to the Fixed Cost Recovery Deferral ("FCR") mechanism that was approved in the 2012 GRA Decision. To facilitate the stabilization plan, the amounts deferred to achieve the average net 3 percent increase would be collected from customers beginning in 2015, when other regulatory assets are fully amortized and these new recoveries can be absorbed. In the absence of the requested rate stabilization plan, average net rate increases of approximately 8 percent and 3 percent respectively for 2013 and 2014 would be necessary, applying traditional cost of service ratemaking procedures.

On December 21, 2012, the UARB approved a settlement agreement, with a few minor adjustments, between NSPI and customer representatives which resulted in an average net 3 percent increase in rates by customer class effective January 1, 2013 and again on January 1, 2014. NSPI committed to $27.5 million in non-fuel cost savings over a two-year period beginning in fiscal 2013. The $27.5 million along with the minor adjustments in the decision reduces the amount of deferred costs resulting from the stabilization plan that can be collected from customers beginning in 2015. Therefore, the deferred balance at the end of 2014 cannot exceed $83.3 million. The deferral recovery will commence when other regulatory assets are fully amortized beginning in 2015. The 2013 GRA settlement agreement reduced NSPI's targeted regulated return on equity ("ROE") for 2013 and 2014 to 8.75 percent to 9.25 percent, down from the 2012 range of 9.1 percent to 9.5 percent, based on an actual average regulated common equity component of up to 40 percent, which is unchanged from 2012.

FAM Audit Decision

On December 21, 2012, the UARB disallowed $4.5 million of fuel-related costs to be applied against the 2013 FAM balance. Including interest of $0.7 million, this resulted in an after-tax effect to 2012 net income of $3.6 million. The decision also disallowed $2.0 million which was applied in 2012 and reduced a regulatory asset owed from customers.

UARB Decision on 2013 Fuel Adjustment Mechanism

On December 10, 2012, the UARB approved NSPI's request for recovery of $45.9 million of prior years' unrecovered fuel-related costs as submitted in NSPI's November FAM 2012 filing, subject to any changes related to the 2013 GRA Decision. On December 21, 2012, the UARB released their decision on the 2013 GRA. No changes were required as a result of this decision.

Pacific West Commercial Corporation Load Retention Tariff

On April 27, 2012, NSPI filed with the UARB, as a co-applicant with Pacific West Commercial Corporation ("PWCC"), for approval of a Load Retention Tariff mechanism and other commercial arrangements relating to the operation of a paper mill in Port Hawkesbury, Nova Scotia. NSPI would have had an indirect interest in the partnership through an equity interest in the majority limited partner.

On September 27, 2012, a modified load retention tariff, without NSPI as a shareholder, was approved by the UARB and ensures the mill covers NSPI's incremental operating costs and contributes to non-fuel costs. On September 28, 2012, PWCC resumed a significant portion of the mill's operations under this tariff.

Successful Wind Energy Bid

On August 2, 2012, the Renewable Energy Administrator ("REA") appointed by the Government of Nova Scotia, solicited bids for the supply of at least 300 gigawatt hours ("GWh") of wind energy, under 20 year contract terms. NSPI was a participant, as a co-developer and investor, in each of the three successful bids, in that solicitation, having committed to invest up to a maximum 49 percent interest in each of the projects. NSPI's participation is subject to UARB approval. The projects are planned to be in service by the end of 2014. On December 20, 2012, NSPI filed a capital work order with the UARB for $93.1 million related to a significant portion of NSPI's share of two of the bids.

United States Securities Exchange Commission Registration Termination

On December 12, 2011, NSPI filed with the 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. Effective March 12, 2012, the SEC review period expired, and NSPI's reporting obligations under United States securities laws terminated. NSPI will continue to report its financial results in accordance with USGAAP, as approved by Canadian securities regulators.

Maine Utility Operations

Regulatory Filings

On November 29, 2012, Bangor Hydro and MPS submitted a regulatory filing with the MPUC seeking permission to merge into one entity. This proposed change is also subject to regulatory approval by the FERC. A decision from the regulators is expected in Q3 2013. The merger application includes a proposal to harmonize distribution rates for most residential and small commercial customers on a revenue neutral basis. No change is proposed to other rates or rate classes.

Caribbean Utility Operations

Preferred Share Issuance

On January 16, 2013, GBPC issued thirty-two thousand non-voting cumulative redeemable perpetual variable preferred shares at $1,000 Bahamian per share for gross proceeds of $32.0 million Bahamian and net proceeds of $30.9 million Bahamian. The net proceeds of the share offering will be used to repay intercompany loans with Emera for construction of the West Sunrise Plant.

GBPC Regulatory Rate Structure Changes

On January 17, 2013, GBPC and the GBPA finalized an Operating Protocol and Regulatory Framework Agreement. This agreement formalizes the operating protocols and regulatory construct GBPC agreed to in principle in June 2012, when the GBPA approved GBPC's new rate structure. The new regulatory rate structure, which became effective July 1, 2012, consists of two components:

- a base rate intended to recover GBPC's operating expenses, depreciation and return on capital investment; and
- a fuel charge intended to recover all of GBPC's fuel costs

As part of the initial rate case filing under the new regulatory structure, the GBPA approved a return on rate base of 10 percent. Every three years, commencing in January 2016, base rates will be reviewed and set by the GBPA.

Appointments

Directors

Effective February 8, 2013, B. Lynn Loewen, FCA joined the Emera Board of Directors. Ms. Loewen is presently Chief Operating Officer of Minogue Medical Inc. in Montreal, Quebec.

Executive

Effective January 8, 2013, Rob Bennett was appointed Executive Vice President and Chief Operating Officer of Emera; Bob Hanf was appointed President and Chief Executive Officer of NSPI and Sarah MacDonald was appointed President of Emera Caribbean Limited, a wholly-owned subsidiary of Emera. Previously, Mr. Bennett was President and Chief Executive Officer of NSPI; Mr. Hanf was Executive Chairman of LPH, a subsidiary of Emera; Ms. MacDonald was President of GBPC, a subsidiary of Emera. Ms. MacDonald is replacing Mr. Hanf and is assuming additional responsibilities with executive oversight for LPH and all business development activity for Emera's existing affiliates in the Caribbean.

Effective October 22, 2012, Judy Steele, FCA, was appointed President and Chief Operating Officer of Emera Energy. Most recently, Ms. Steele was Interim Chief Financial Officer of Emera. Ms. Steele replaced Wayne O'Connor who was appointed Executive Vice President, Operations for NSPI.

Scott Balfour was appointed Executive Vice President and Chief Financial Officer of Emera and NSPI effective April 16, 2012. Prior to joining Emera, Mr. Balfour was President of Ensimian Capital Corporation, a private company providing consulting services and private investment. Mr. Balfour previously held the position of President and Chief Financial Officer of Aecon Group Inc., a publicly traded construction and infrastructure development company headquartered in Toronto, Ontario.

Significant Items

Gains on Exchange of Subscription Receipts to Shares

The following table outlines the subscription receipt transactions which have been converted to shares, and their associated after-tax gains:

Underlying Transaction	Quarter Transaction Closed		After-tax gain on conversion of Subscription Receipts to APUC shares (millions of Canadian dollars)
Acquisition of California Pacific	Q1 2011	$	12.8
New Hampshire Transaction	Q2 2012		11.6
Gamesa - 1/2 of first tranche	Q3 2012		1.8
Atmos	Q3 2012		0.9
Sale of CPUV - first tranche	Q4 2012		8.4
Gamesa - 1/2 of first tranche	Q1 2013		3.6
Total		$	39.1

Gain on Business Acquisition

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 were recorded in "Other income (expenses), net".

REVIEW OF 2012
Emera Consolidated Statements of Income

For the millions of Canadian dollars (except per share amounts)		Three months ended December 31			Year ended December 31	
		2012	2011	**2012**	2011	2010
Operating revenues – regulated	**$**	**489.6** $	461.7 **$**	**1,912.7** $	1,891.0 $	1,411.6
Operating revenues – non-regulated		**23.3**	50.3	**145.9**	173.4	194.5
Total operating revenues		**512.9**	512.0	**2,058.6**	2,064.4	1,606.1
Regulated fuel for generation and purchased power		**210.7**	215.0	**810.5**	866.4	634.6
Regulated fuel and fixed cost adjustments		**2.0**	(4.5)	**10.0**	(8.5)	(99.0)
Non-regulated fuel for generation and purchased power		**11.1**	18.3	**44.5**	73.9	83.9
Non-regulated direct costs		**14.7**	20.4	**56.6**	60.9	62.3
Operating, maintenance and general		**127.9**	121.5	**462.9**	453.3	349.4
Provincial, state and municipal taxes		**12.4**	12.5	**49.4**	49.2	47.4
Depreciation and amortization		**89.4**	74.1	**278.2**	251.7	215.3
Total operating expenses		**468.2**	457.3	**1,712.1**	1,746.9	1,293.9
Income from operations		**44.7**	54.7	**346.5**	317.5	312.2
Income from equity investments		**1.1**	6.7	**17.5**	34.3	21.6
Other income (expenses), net		**14.4**	1.5	**36.3**	43.1	12.5
Interest expense, net		**41.5**	37.3	**167.1**	159.4	148.8
Income before provision for income taxes		**18.7**	25.6	**233.2**	235.5	197.5
Income tax expense (recovery)		**(27.9)**	(23.8)	**(12.4)**	(23.9)	(1.8)
Net income		**46.6**	49.4	**245.6**	259.4	199.3
Non-controlling interest in subsidiaries		**3.9**	2.6	**13.7**	11.7	5.6
Net income of Emera Incorporated		**42.7**	46.8	**231.9**	247.7	193.7
Preferred stock dividends		**-**	-	**11.1**	6.6	3.0
Net income attributable to common shareholders		**42.7**	46.8	**220.8**	241.1	190.7
Earnings per common share – basic	**$**	**0.34** $	0.38 **$**	**1.77** $	1.99 $	1.67
Earnings per common share – diluted	**$**	**0.34** $	0.38 **$**	**1.76** $	1.97 $	1.65

Emera Incorporated's consolidated net income decreased $4.1 million to $42.7 million in Q4 2012 compared to $46.8 million in Q4 2011. For the year ended December 31, 2012, Emera's consolidated net income decreased $20.3 million to $220.8 million compared to $241.1 million in 2011. 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 – 2010		**$ 190.7**
Operating revenues – Increased primarily due to higher fuel-related revenues in NSPI		17.4
Regulated fuel for generation and purchased power – Decreased primarily due to lower commodity prices and a change in the generation mix		41.8
Regulated fuel and fixed cost adjustments – Decreased due to an under-recovery of current period fuel costs and change in recovery of prior periods' FAM balance		(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		22.1
Impact of the acquisitions of GBPC, MPS and LPH		47.7
Other		11.9
Consolidated net income attributable to common shareholders – 2011	**$ 46.8**	**$ 241.1**
Operating revenues – regulated – Increased quarter-over-quarter primarily due to increased rates in NSPI and a weaker US dollar; increased year-over-year primarily due to increased rates in NSPI and BHE and increased investment in LPH as of January 25, 2011, partially offset by decreased industrial sales volumes in NSPI due to two large industrial customers suspending operations, decreased rates in MPS and a stronger US dollar	27.9	21.7
Operating revenues – non-regulated – Decreased primarily due to a planned maintenance outage and lower priced contracted energy sales at Bayside Power reflecting lower natural gas prices, a net mark-to-market loss in Emera Energy Services and reduced construction activity in Utility Services, partially offset by stronger energy marketing results in Emera Energy Services	(27.0)	(27.5)
Regulated fuel for generation and purchased power – Decreased quarter-over-quarter primarily due to lower temporary generation costs, improved plant performance in GBPC and a weaker US dollar, partially offset by increased sales volumes and higher commodity prices in NSPI; year-over-year decreased primarily due to lower sales volumes in NSPI and lower temporary generation costs and improved plant performance in GBPC	4.3	55.9
Regulated fuel and fixed cost adjustments – Increased primarily due to NSPI's increased recovery of prior years' fuel costs from customers, partially offset by a lower under recovery of current periods' fuel costs from customers and the deferral of fixed costs related to two large industrial customers	(6.5)	(18.5)
Non-regulated fuel for generation and purchased power – Decreased primarily due to a planned maintenance outage at Bayside Power and lower natural gas prices	7.2	29.4
Non-regulated direct costs – Decreased primarily due to changes in construction activity in Utility Services	5.7	4.3
Operating, maintenance and general – Increased primarily due to business development activities, lower capitalized construction overheads and increased pension and medical expenses in Bangor Hydro and deferred compensation costs; year-over-year also due to reversal of a receivable allowance of a large customer, decreased plant maintenance spending and storm costs, partially offset by increased pension costs in NSPI and transitional costs associated with new generation in GBPC	(6.4)	(9.6)

Depreciation and amortization – Increased primarily due to additional amortization of pre-2003 income tax regulatory asset and increased depreciation resulting from increased property, plant and equipment and new depreciation rates effective January 1, 2012 in NSPI	(15.3)	(26.5)
Income from equity investments – Decreased quarter-over-quarter primarily due to mark-to-market losses in NWP and an unplanned outage in Bear Swamp; decreased year-over-year also primarily due to decreased income in CPUV and in APUC as a result of unfavorable weather and lower sales respectively	(5.6)	(16.8)
Other income (expenses), net – Increased income quarter-over-quarter primarily due to APUC subscription receipts, recognition of a regulatory asset in GBPC and gain on the sale of CPUV investment; decreased income year-over-year also primarily due to a gain on acquisition of a controlling interest in LPH of $28.2 million in 2011	12.9	(6.8)
Interest expense, net – Increased year-over-year primarily due to higher long-term debt levels	(4.2)	(7.7)
Income tax recovery – Increased income tax recovery quarter-over-quarter primarily due to decreased income before provision for income taxes and increased non-taxable income in the Caribbean; decreased income tax recovery year-over-year primarily due to NSPI having fewer accelerated tax deductions related to property, plant and equipment and the prior year reduction in FAM regulatory asset, partially offset by increased tax deductions related to pension contributions	4.1	(11.5)
Preferred stock dividends – Increased due to issuance of series C preferred shares	-	(4.5)
Other	(1.2)	(2.2)
Consolidated net income attributable to common shareholders – 2012	**$ 42.7**	**$ 220.8**

Consolidated Balance Sheets Highlights

Significant changes in the consolidated balance sheets between December 31, 2012 and December 31, 2011 include:

millions of Canadian dollars	Increase (Decrease)	Explanation
Assets		
Receivables, net	**(10.2)**	Decreased primarily due to settlement of financial positions and timing of billings and receipts, partially offset by increased electricity rates.
Income taxes receivable	**13.3**	Increased primarily due to recovery of income taxes in NSPI from increased tax deductions related to pension contributions.
Inventory	**(21.2)**	Decreased primarily due to solid fuel inventory volumes in NSPI.
Derivative instruments (current and long-term)	**(19.4)**	Decreased primarily due to settlements, unfavourable commodity price positions and unfavourable USD price positions in NSPI.
Regulatory assets (current and long-term)	**20.3**	Increased primarily due to deferred income taxes and fixed cost recovery deferral in NSPI, recognition of a regulatory asset in GBPC and deferred income taxes in Pipelines, partially offset by decreases related to the FAM, regulatory amortization and derivatives in NSPI.
Other assets (current and long-term)	**(134.7)**	Decreased primarily due to net settlement of subscription receipts, cancellation of subscription receipts related to the First Wind transaction and reclassification of subscription receipts to available-for-sale investments.
Property, plant and equipment, net of accumulated depreciation	**196.7**	Increased primarily due to capital spending, partially offset by depreciation.
Investments subject to significant influence	**316.8**	Increased primarily due to investment in NWP and increased investment in APUC.
Available-for-sale investments	**87.2**	Increased primarily due to new subscription receipts.
Intangibles, net of accumulated amortization	**13.5**	Increased primarily due to purchase of transmission right of way in Bangor Hydro.
Due from related parties	**148.9**	Increased due to loan to NWP.
Liabilities and Equity		
Short-term debt and long-term debt (including current portion)	**186.2**	Increased debt levels primarily due to investment in NWP, increased investment in APUC and capital spending, partially offset by proceeds from the issuance of common and preferred shares.
Accounts payable	**(38.1)**	Decreased primarily due to timing of payments and fuel shipments in NSPI.
Deferred income taxes (current and long-term)	**76.1**	Increased primarily due to NSPI's accelerated tax deductions related to property, plant and equipment.
Derivative instruments (current and long-term)	**(31.3)**	Decreased primarily due to settlements, partially offset by unfavorable USD price positions in NSPI.
Regulatory liabilities (current and long-term)	**(20.3)**	Decreased primarily due to derivatives in NSPI.
Pension and post-retirement liabilities (current and long-term)	**(23.4)**	Decreased primarily due to NSPI's cash contributions, partially offset by increased obligations due to a change in the discount rate used in determining the pension and post-retirement obligations.
Common stock	**258.7**	Increased due to issuance of common shares.
Cumulative preferred stock	**244.9**	Increased due to issuance of preferred shares.
Accumulated other comprehensive loss	**104.1**	Increased primarily due to net change in unrecognized pension and post-retirement benefit costs resulting primarily due to a change in the discount rate in NSPI and unfavorable effect of a stronger CAD on Emera's foreign subsidiaries.
Retained earnings	**52.2**	Net income in excess of dividends paid.

Outstanding Common Stock Data

Issued and outstanding:	millions of shares	Common stock millions of Canadian dollars
December 31, 2010	114.62	$ 1,137.8
Issuance of common stock	6.36	196.0
Issued for cash under Employee Stock Purchase Plans at market rate	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
Issuance of common stock	5.91	193.2
Issued for cash under Employee Stock Purchase Plans at market rate	1.55	52.0
Discount on shares purchased under Dividend Reinvestment Plan	-	(2.3)
Options exercised under senior management stock option plan	0.69	13.9
Stock-based compensation	-	1.9
December 31, 2012	**130.98**	**$ 1,643.7**

As at January 25, 2013, the amount of issued and outstanding common shares was 131.03 million.

The weighted average shares of common stock outstanding – basic for the three months ended December 31, 2012 was 126.6 million (2011 – 123.1 million). The weighted average shares of common stock outstanding – basic for the year ended December 31, 2012 was 124.9 million (2011 – 121.0 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 with approximately $4.0 billion of assets and is the primary electricity supplier in Nova Scotia. NSPI provides electricity generation, transmission and distribution services to approximately 497,000 customers. The Company owns 2,423 MW of generating capacity, of which approximately 51 percent is coal-fired; natural gas and/or oil comprise another 29 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 265 MW, increasing to 276 MW in 2013 of wind and biomass-fueled generation capacity. A further 176 MW of renewable capacity is being built directly or purchased under long-term contracts by NSPI of which 60 MW is expected to be in service by the end of 2013 and the remainder is expected to be in service by the end of 2014. NSPI also owns approximately 5,000 kilometers of transmission facilities and 27,000 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 2012 was 9.1 percent to 9.5 percent, based on an actual average regulated common equity component of up to 40 percent of actual average regulated capitalization. The 2013 General Rate Decision adjusted the targeted regulated ROE range to 8.75 percent to 9.25 percent for 2013 and 2014.

On December 21, 2012, the UARB approved a General Rate Application ("GRA") settlement agreement between NSPI and customer representatives, which results in an average net increase of 3 percent by customer class effective January 1, 2013 and again on January 1, 2014. Rates were approved based on a 9.0 percent regulated ROE, applied to a 37.5 percent regulated common equity component.

In Q4 2011, the UARB approved a GRA 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 regulated 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.

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

Review of 2012

NSPI Net Income

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2012	2011	**2012**	2011	2010
Operating revenues – regulated	**$ 324.8**	$ 289.2	**$ 1,237.2**	$ 1,233.0	$ 1,191.4
Regulated fuel for generation and purchased power (1)	**135.9**	127.8	**494.9**	547.4	586.7
Regulated fuel and fixed cost adjustments	**2.0**	(4.5)	**10.0**	(8.5)	(99.0)
Operating, maintenance and general	**73.1**	75.0	**259.8**	268.6	245.8
Provincial grants and taxes	**9.4**	9.8	**37.8**	38.7	40.1
Depreciation and amortization	**73.8**	58.8	**212.3**	187.2	188.1
Total operating expenses	**294.2**	266.9	**1,014.8**	1,033.4	961.7
Income from operations	**30.6**	22.3	**222.4**	199.6	229.7
Other expenses net (2)	**1.0**	2.1	**4.2**	8.9	11.3
Interest expense, net	**29.1**	23.6	**113.3**	104.2	104.7
Income before provision for income taxes	**0.5**	(3.4)	**104.9**	86.5	113.7
Income tax expense (recovery)	**(28.4)**	(27.5)	**(29.0)**	(44.9)	(13.4)
Net income of Nova Scotia Power Inc.	**28.9**	24.1	**133.9**	131.4	127.1
Preferred stock dividends	**1.9**	1.9	**7.9**	7.9	7.9
Contribution to consolidated net income	**$ 27.0**	$ 22.2	**$ 126.0**	$ 123.5	$ 119.2
Contribution to consolidated earnings per common share	**$ 0.21**	$ 0.18	**$ 1.01**	$ 1.02	$ 1.04

(1) Fuel for generation and purchased power includes affiliate transactions and proceeds from the sale of natural gas.
(2) Other expenses, net is included in "Other income (expenses), net" on the Consolidated Statements of Income.

NSPI's contribution to consolidated net income increased $4.8 million to $27.0 million in Q4 2012 compared to $22.2 million in Q4 2011. For the year ended December 31, 2012, NSPI's contribution to consolidated net income increased $2.5 million to $126.0 million compared to $123.5 million in 2011. 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 – 2010		**$ 119.2**
Decreased electric margin (see Electric Margin section for explanation)		(6.9)
Increased operating, maintenance and general ("OM&G") expenses primarily due to increased pension costs, plant maintenance costs and labour escalation		(22.8)
Decreased net depreciation and amortization primarily due to decreased regulatory amortization, partially offset by increased property, plant and equipment (1)		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		31.5
Other (1)		0.8
Contribution to consolidated net income – 2011	**$ 22.2**	**$ 123.5**
Increased electric margin (see Electric Margin section for explanation)	20.3	40.3
Decreased OM&G expenses year-over-year primarily due to reversal of a receivable allowance of a large customer, decreased plant maintenance spending and storm costs, partially offset by increased pension costs	1.9	8.8
Increased depreciation and amortization primarily due to additional amortization of pre-2003 income tax regulatory asset and increased depreciation resulting from increased property, plant and equipment and new depreciation rates effective January 1, 2012 (1)	(15.3)	(26.4)
Increased interest expense, net primarily due to higher long-term debt levels and decreased interest revenues related to the election to amend prior year income tax returns in 2011 (1)	(5.8)	(10.1)
Decreased income tax recovery year-over-year primarily due to fewer accelerated tax deductions related to property, plant and equipment; the prior year included a deferred tax recovery resulting from a reduction in a FAM regulatory asset; and increased income before provision for income taxes, partially offset by increased tax deductions related to pension contributions	0.9	(15.9)
Other (1)	2.8	5.8
Contribution to consolidated net income – 2012	**$ 27.0**	**$ 126.0**

(1) Amounts exclude variances included in the calculation of electric margin

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		
	2012	2011	**2012**	2011	2010
Electric revenues	**$ 316.7**	$ 282.9	**$ 1,210.4**	$ 1,209.7	$ 1,167.3
Other revenues	**8.1**	6.3	**26.8**	23.3	24.1
Operating revenues – regulated	**$ 324.8**	$ 289.2	**$ 1,237.2**	$ 1,233.0	$ 1,191.4

Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal, with Q1 being the strongest period, 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")

	2012	2011	2010
Residential	**1,098**	1,073	1,080
Commercial	**786**	768	765
Industrial	**657**	568	957
Other	**86**	83	84
Total	**2,627**	2,492	2,886

Annual Electric Sales Volumes
GWh

	2012	2011	2010
Residential	**4,186**	4,275	4,147
Commercial	**3,099**	3,102	3,088
Industrial	**2,167**	3,516	3,908
Other	**337**	313	312
Total	**9,789**	11,206	11,455

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

Q4 Electric Revenues
millions of Canadian dollars

	2012	2011	2010
Residential	**$ 158.1**	$ 141.0	$ 137.1
Commercial	**94.1**	85.8	82.2
Industrial	**52.8**	45.2	66.0
Other	**11.7**	10.9	11.1
Total	**$ 316.7**	$ 282.9	$ 296.4

Annual Electric Revenues
millions of Canadian dollars

	2012	2011	2010
Residential	**$ 606.8**	$ 564.9	$ 531.0
Commercial	**367.2**	341.8	325.4
Industrial	**190.6**	260.1	269.3
Other	**45.8**	42.9	41.6
Total	**$ 1,210.4**	$ 1,209.7	$ 1,167.3

Electric revenues increased $33.8 million to $316.7 million in Q4 2012 compared to $282.9 million in Q4 2011. For the year ended December 31, 2012, electric revenues increased $0.7 million to $1,210.4 million compared to $1,209.7 million in 2011. 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 – 2010		**$ 1,167.3**
Increased fuel-related electricity pricing effective January 1, 2011		51.5
Increased residential sales volumes due to load growth and colder weather		15.2
Decreased industrial sales volume primarily due to suspended operations of a large industrial customer		(24.1)
Other		(0.2)
Electric revenues – 2011	**$ 282.9**	**$ 1,209.7**
Increased electricity pricing effective January 1, 2012	14.3	51.5
Increased electricity pricing effective January 1, 2012 related to recovery of prior years' fuel costs	10.7	42.5
Increased industrial sales volumes quarter-over-quarter due to a large industrial customer resuming operation in September 2012; decreased industrial sales volumes year-over-year primarily due to two large industrial customers suspending operations (see Regulated Fuel and Fixed Cost Adjustments section)	3.3	(84.3)
Increased residential sales quarter-over-quarter primarily due to favourable weather; decreased year-over-year residential sales volumes primarily due to unfavourable weather and decreased load	3.4	(10.4)
Other	2.1	1.4
Electric revenues – 2012	**$ 316.7**	**$ 1,210.4**

Regulated Fuel for Generation and Purchased Power

Capacity

To ensure reliability of service, NSPI must maintain a generating capacity greater than firm peak demand. The total Company-owned generation capacity is 2,423 MW, which is supplemented by 265 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 performance indicators. The high availability and capability of low cost thermal generating stations provide lower cost energy to customers. In 2012, thermal plant availability was 81 percent compared to 87 percent in 2011. This ranks in the top quartile of the Canadian Electricity Association statistics. The reduction in availability was due to advantageous natural gas market conditions allowing for extended maintenance periods of the coal facilities.

Q4 Production Volumes
GWh

	2012	2011	2010
Coal and petcoke	**1,864**	1,624	2,049
Natural gas	**377**	482	438
Oil	**5**	7	16
Renewables	**328**	327	340
Purchased power – renewables	**255**	227	175
Purchased power – other	**48**	71	140
Total	**2,877**	2,738	3,158

Annual Production Volumes
GWh

	2012	2011	2010
Coal and petcoke	**6,223**	6,848	7,839
Natural gas	**2,158**	2,430	2,275
Oil	**12**	35	36
Renewables	**1,084**	1,335	1,017
Purchased power – renewables	**838**	743	526
Purchased power – other	**194**	526	471
Total	**10,509**	11,917	12,164

Q4 Average Fuel Costs

	2012	2011	2010
Dollars per megawatt hour ("MWh")	**$ 47**	$ 47	$ 46

Annual Average Fuel Costs

	2012	2011	2010
Dollars per MWh	**$ 47**	$ 46	$ 48

NSPI's percentage of solid fuel generation was approximately 59 percent in 2012, up from 57 percent in 2011 and down from 64 percent in 2010. 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. In the last two years, economic dispatch has favoured natural gas over coal. However, during the latter part of 2012, due to volatility in natural gas markets in Nova Scotia, this has reversed.

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. The adoption of the FAM, effective January 1, 2009, has further helped NSPI manage this risk. Further details on NSPI's risk management strategies related to regulated fuel for generation and purchased power are discussed in the Business Risks section.

Regulated fuel for generation and purchased power increased $8.1 million to $135.9 million in Q4 2012 compared to $127.8 million in Q4 2011. For the year ended December 31, 2012, regulated fuel for generation and purchased power decreased $52.5 million to $494.9 million compared to $547.4 million in 2011. 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
Regulated fuel for generation and purchased power – 2010		**$ 586.7**
Valuation of contract receivable (1)		27.8
Changes in generation mix and plant performance		45.9
Decreased commodity prices		(77.2)
Increased hydro and wind production		(16.0)
Changes in solid fuel commodity mix and additives related to emission compliance		(2.9)
Decreased sales volume		(12.4)
Other		(4.5)
Regulated fuel for generation and purchased power – 2011	**$ 127.8**	**$ 547.4**
Changes in sales volume	5.3	(71.6)
Increased commodity prices	6.4	6.9
Changes in generation mix and plant performance	(3.4)	(5.0)
Decreased renewable production due to lower hydro production	-	12.2
Other	(0.2)	5.0
Regulated fuel for generation and purchased power – 2012	**$ 135.9**	**$ 494.9**

(1) NSPI had a long-term 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.

Regulated Fuel and Fixed Cost Adjustments

Regulated Fuel Adjustment and FAM Regulatory Asset

NSPI has a Fuel Adjustment Mechanism ("FAM") which enables it 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. Prior to 2012, the FAM had an incentive component whereby NSPI retained or absorbed 10 percent of the over or under recovered amount to a maximum of $5 million. In November 2011, the UARB suspended the FAM incentive component for 2012 as part of the settlement agreement in the 2012 GRA Decision. The 2013 GRA settlement agreement, approved on December 21, 2012 by the UARB, continues the suspension of the FAM incentive component for 2013 and 2014.

Pursuant to the FAM Plan of Administration, NSPI's fuel costs are subject to independent audit. The first audit completed was for fiscal 2009, with no financial implications. The second audit completed was for fiscal 2010 and fiscal 2011, and on December 21, 2012, the UARB disallowed $4.5 million of fuel-related costs to be applied against the 2013 FAM balance. Including interest of $0.7 million, this resulted in an after-tax effect to 2012 net income of $3.6 million. The decision also disallowed $2.0 million, which was applied in 2012 and reduced a regulatory asset owed from customers.

On December 10, 2012, The UARB approved NSPI's request for recovery of $45.9 million of prior years' unrecovered fuel-related costs as submitted in NSPI's November 2012 FAM filing, subject to any changes related to the 2013 GRA Decision. On December 21, 2012, the UARB released their decision on the 2013 GRA. No changes were required as a result of this decision.

On December 19, 2011, the UARB approved NSPI's request associated with 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.

The regulated fuel adjustment included in "Regulated Fuel and fixed cost adjustments" on the Statements of Income related to the FAM includes the effect of fuel costs in both the current and preceding years, specifically:

- The difference between actual fuel costs and amounts recovered from customers in the current year. This amount 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 costs from prior years.

As at December 31, 2012, the FAM regulatory asset was $43.1 million (December 31, 2011 – $93.7 million) and is classified in "Regulatory assets" on the Consolidated Balance Sheets. The FAM regulatory asset includes amounts recognized as a fuel adjustment and associated interest that is included in "Interest expense, net" " on the Consolidated Statements of Income.

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

millions of Canadian dollars		**2012**
FAM regulatory asset – Balance as at January 1	$	93.7
Under (over) recovery of current year fuel costs		15.7
Rebate to (recovery from) customers of prior years' fuel costs		(65.9)
FAM audit disallowance including interest adjustment		(5.2)
Interest revenue on FAM regulatory asset		4.8
FAM regulatory asset – Balance as at December 31	**$**	**43.1**

NSPI has recognized a deferred income tax recovery related to the regulated fuel adjustment based on NSPI's enacted statutory tax rate. As at December 31, 2012, NSPI's deferred income tax liability related to the FAM was $13.4 million (December 31, 2011 – $29.0 million).

Regulated Fixed Cost Adjustment and FCR Regulatory Asset

During 2012, the UARB approved a Fixed Cost Recovery Deferral ("FCR"). The FCR was intended to address uncertainty associated with the operations of two large industrial customers who experienced financial challenges and idled their mills. In the event that actual sales to these customers in 2012 were less than expected when rates were set, the resultant shortfall in contribution toward non-fuel expenses was deferred for future recovery. The FCR was effective for the 2012 fiscal year, and the 2013 GRA settlement agreement approved on December 21, 2012 by the UARB, allows recovery from customers over a three year period commencing January 1, 2013.

As at December 31, 2012, the FCR regulatory asset was $ 46.7 million (December 31, 2011 – nil) and is classified in "Regulatory assets" on the Consolidated Balance Sheets. The FCR regulatory asset includes amounts recognized as a fixed cost adjustment and associated interest that is included in "Interest expense, net" on the Consolidated Statements of Income.

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

millions of Canadian dollars		**2012**
FCR regulatory asset – Balance as at January 1	$	-
Under (over) recovery of current year non-fuel expenses		44.7
Interest revenue on FCR balance		2.0
FCR regulatory asset – Balance as at December 31	**$**	**46.7**

NSPI has recognized a deferred income tax expense related to the FCR based on NSPI's enacted statutory tax rate. As at December 31, 2012, NSPI's deferred income tax liability related to the FCR was $14.5 million (December 31, 2011 – nil).

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 effectively seeks to recover all prudently incurred fuel costs, and consequently, fuel electric revenues and fuel costs do not have a material effect on NSPI's electric margin or net income, except for the incentive component, where applicable. For 2012, electric margin was also affected by the FCR which deferred recovery of non-fuel costs associated with two large industrial customers, with the result that reduced sales to these customers had no impact on NSPI's electric margin in 2012.

Electric margin and net income are influenced primarily by revenues relating to non-fuel costs. NSPI's customer classes contribute differently to NSPI's non-fuel electric revenues, with residential and commercial customers contributing more than industrials. Accordingly, changes in residential and commercial load, largely due to the effects of weather and general economic 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. For 2012, the unrecovered non-fuel electric revenues from two large industrial customers were deferred.

The addition of new generation facilities to meet greenhouse gas reductions and renewable energy requirements is increasing NSPI's fixed costs. Electric margin, which represents the revenues available to cover these costs, has increased in a corresponding manner.

Electric margin is summarized in the following table:

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
	2012	2011	**2012**	2011	2010
Operating revenues – regulated	**$ 324.8**	$ 289.2	**$ 1,237.2**	$ 1,233.0	$ 1,191.4
Less: Other revenues	**(8.1)**	(6.3)	**(26.8)**	(23.3)	(24.1)
Total electric revenues	**316.7**	282.9	**1,210.4**	1,209.7	1,167.3
Total electric revenues is broken down as follows:					
Fuel electric revenues – current year	**$ 128.5**	$ 115.6	**$ 481.2**	$ 512.6	$ 513.7
Fuel electric revenues – preceding years	**16.7**	6.1	**65.9**	26.6	(22.4)
Non-fuel electric revenues	**171.5**	161.2	**663.3**	670.5	676.0
Total electric revenues	**316.7**	282.9	**1,210.4**	1,209.7	1,167.3
Regulated fuel for generation and purchased power	**(135.9)**	(127.8)	**(494.9)**	(547.4)	(586.7)
Regulated fuel adjustment	**(13.3)**	4.5	**(54.7)**	8.5	99.0
Regulated fixed cost adjustment	**11.3**	-	**44.7**	-	-
Fuel-related foreign exchange and other fuel-related costs (1)	**(0.3)**	(1.4)	**(1.8)**	(7.4)	(9.3)
Electric margin	**$ 178.5**	$ 158.2	**$ 703.7**	$ 663.4	$ 670.3

(1) As reported in "Other income (expense) net", "Depreciation and amortization", and "Interest expense, net" on the Consolidated Statements of Income.

NSPI's electric margin increased $20.3 million to $178.5 million in Q4 2012 compared to $158.2 million in Q4 2011 primarily due to increased rates across all customer classes and the deferral of costs resulting from decreased industrial load in 2012 through the UARB approved FCR mechanism, partially offset by the disallowance of fuel-related costs. For the year ended December 31, 2012, NSPI's electric margin increased $40.3 million to $703.7 compared to $663.4 million in 2011 primarily due to increased rates across all customer classes and the deferral of costs resulting from decreased industrial load in 2012 through the UARB approved FCR mechanism, partially offset by decreased residential sales as a result of unfavourable weather, load decreases and the disallowance of fuel-related costs.

Q4 Average Electric Margin / MWh

	2012	2011	2010
Dollars per MWh	**$ 68**	$ 63	$ 59

Annual Average Electric Margin / MWh

	2012	2011	2010
Dollars per MWh	**$ 72**	$ 59	$ 59

The increase in average electric margin per MWh in Q4 2012 compared to Q4 2011 reflects increased electricity rates and the deferral of costs resulting from decreased industrial load in 2012 through the UARB approved FCR mechanism, partially offset by changes in customer mix due to a large customer resuming operations.

The change in average electric margin per MWh for the year ended December 31, 2012 compared to 2011 reflects increased electricity rates, the deferral of costs resulting from decreased industrial load in 2012 through the UARB approved FCR mechanism and changes in customer mix.

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 increased $12.4 million to $28.4 in Q4 2012 compared to $16.0 million in Q4 2011 and increased $14.3 million to $33.4 million for the year ended December 31, 2012 compared to $19.1 million in 2011 primarily due to $9.8 million (2011 – $0.1 million) of additional amortization of the pre-2003 income tax regulatory asset resulting from the UARB’s 2010 ROE decision and an additional $2.0 million in amortization of the pre-2003 income tax regulatory asset as a result of the 2013 UARB decision related to the FAM audit. The 2010 ROE decision allows NSPI flexibility in the recognition of additional amortization in current periods, which accordingly reduces amortization in future periods relating to customer rate requirements.

Income Taxes

In 2012, NSPI was subject to provincial capital tax (0.025 percent), corporate income tax (31 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 (28 percent of preferred stock dividends).

In Q4 2012, NSPI contributed an additional amount to its defined benefit pension plan resulting in tax savings of $31.1 million.

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 Q4 2011.

MAINE UTILITY OPERATIONS

Overview

Maine Utility Operations ("Maine Utilities") includes Bangor Hydro Electric Company ("Bangor Hydro") and Maine Public Service Company ("MPS"). All amounts in the Maine Utility Operations section are reported in USD unless otherwise stated. Emera acquired MPS on December 21, 2010, thus its results are not included in 2010 comparative information.

Bangor Hydro and MPS are both transmission and distribution ("T&D") electric utilities. Bangor Hydro is the second largest utility in Maine. Bangor Hydro has approximately $845.0 million of assets and serves approximately 120,000 customers in eastern Maine, while MPS has approximately $145.0 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 110 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 local 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 by the MPUC 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 and regulated 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, 2012, Bangor Hydro's local transmission rates increased by approximately 4 percent (2011 – decreased 10 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 the customers of participating transmission providers in New England, based on a regional formula determined by FERC 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, 2011, Bangor Hydro's regionally recoverable transmission investments and expenses increased by 9 percent, and on June 1, 2012, it increased by a further 18 percent.

MPS

MPS local transmission rates are set and regulated by the FERC annually on June 1, based upon a formula utilizing prior year actual transmission investments and expenses. These rates go into effect June 1 for wholesale customers and July 1 for retail customers. The current allowed ROE for transmission operations is 10.5 percent, and is based on the actual prior calendar year common equity balances. On June 1, 2012, MPS' local transmission rates increased by 9 percent for wholesale customers (2011 – increased 3 percent) and then decreased by 17 percent for wholesale customers and by 5 percent for retail customers (2011 – increased by 4 percent) on July 1, 2012.

MPS' electric service territory is not interconnected to the New England bulk power system, and MPS is not a member of the ISO.

<u>Stranded Cost Recoveries</u>

Stranded cost recoveries in Maine are set by the MPUC. Electric utilities 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 transmission and distribution 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 $63.9 million as at December 31, 2012 (2011 – $65.3 million) or 7.5 percent of Bangor Hydro's net asset base (2011 – 8 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, and resulted in an approximately 50 percent rate decrease, 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 2012
Maine Utility Operations' Net Income

For the millions of US dollars (except per share amounts)	Three months ended December 31		For the year ended December 31		
	2012	2011	**2012**	2011	2010
Operating revenues – regulated	**$ 52.3**	$ 50.6	**$ 204.5**	$ 204.1	$ 167.2
Operating revenues – non-regulated	**0.1**	0.1	**0.5**	0.5	-
Total operating revenues	**52.4**	50.7	**205.0**	204.6	167.2
Regulated fuel for generation and purchased power	**8.8**	9.2	**31.7**	27.9	29.2
Transmission pool expense (1)	**5.1**	4.3	**19.4**	17.9	18.3
Operating, maintenance and general	**13.2**	10.2	**49.5**	43.6	34.6
Provincial, state and municipal taxes	**3.0**	2.2	**10.1**	9.0	6.8
Depreciation and amortization	**6.9**	8.8	**31.3**	38.6	22.6
Total operating expenses	**37.0**	34.7	**142.0**	137.0	111.5
Income from operations	**15.4**	16.0	**63.0**	67.6	55.7
Other income (expenses), net	**1.3**	1.6	**5.3**	4.3	4.1
Interest expense, net	**3.2**	2.8	**13.0**	11.8	10.7
Income before provision for income taxes	**13.5**	14.8	**55.3**	60.1	49.1
Income tax expense (recovery)	**4.8**	5.2	**19.9**	22.7	18.2
Contribution to consolidated net income – USD	**$ 8.7**	$ 9.6	**$ 35.4**	$ 37.4	$ 30.9
Contribution to consolidated net income – CAD	**$ 8.6**	$ 9.8	**$ 35.4**	$ 37.0	$ 31.9
Contribution to consolidated earnings per common share – CAD	**$ 0.07**	$ 0.08	**$ 0.28**	$ 0.31	$ 0.28
Net income weighted average foreign exchange rate – CAD/USD	**$ 0.99**	$ 1.02	**$ 1.00**	$ 0.99	$ 1.03

(1) Transmission pool expense is included in “Regulated fuel for generation and purchased power” on the Consolidated Statements of Income.

Maine Utilities’ USD contribution to consolidated net income decreased by $0.9 million to $8.7 million in Q4 2012 compared to $9.6 million in Q4 2011. For the year ended December 31, 2012, Maine Utilities USD contribution to consolidated net income decreased by $2.0 million to $35.4 million compared to $37.4 million in 2011. Highlights of the USD 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 – 2010	**$**	**$ 30.9**
Increased transmission pool revenue primarily due to recovery on larger regionally funded transmission investments, partially offset by unfavourable weather in 2011		2.2
Decreased OM&G expenses in Bangor Hydro primarily due to increased capitalized construction overheads		3.9
Increased income tax expense in Bangor Hydro primarily due to increased income before provision for income taxes		(2.7)
Impact of the acquisition of MPS, net of income taxes		2.7
Other		0.4
Contribution to consolidated net income – 2011	**$ 9.6**	**$ 37.4**
Increased operating revenues – regulated (see Operating Revenues – Regulated Section below)	1.7	0.4
Decreased (increased) regulated fuel for generation and purchased power expense due to changes in long-term purchased power contracts	0.4	(3.8)
Increased transmission pool expense due to new transmission investments in New England	(0.8)	(1.5)
Increased OM&G expenses primarily due to decreased capitalized construction overheads and increased pension and medical expenses	(3.0)	(5.9)
Decreased depreciation and amortization primarily due to the difference between increased purchased power costs and lower stranded cost revenues	1.9	7.3
Decreased income tax expense primarily due to decreased income before provision for income taxes	0.4	2.8
Other	(1.5)	(1.3)
Contribution to consolidated net income – 2012	**$ 8.7**	**$ 35.4**

Maine Utility Operations' CAD contribution to consolidated net income decreased by $1.2 million to $8.6 million in Q4 2012 from $9.8 million in Q4 2011. For the year ended December 31, 2012, Maine Utility Operations' CAD contribution to consolidated net income decreased by $1.6 million to $35.4 million from $37.0 million in 2011. The impact of a weaker USD, quarter-over-quarter, decreased CAD earnings by $0.3 million for the three months ended December 31, 2012. The impact of a stronger USD, year-over-year, increased CAD earnings by $0.4 million for the year ended December 31, 2012.

Operating Revenues – Regulated

Maine Utilities operating revenues – regulated include sales of electricity and other services as summarized in the following table:

Q4 Operating Revenues – Regulated
millions of US dollars

	2012	2011	2010
Electric revenues	**$ 37.5**	$ 37.1	$ 29.0
Transmission pool revenues	**11.0**	8.8	9.2
Resale of purchased power	**3.8**	4.7	4.6
Operating revenues – regulated	**$ 52.3**	$ 50.6	$ 42.8

Annual Operating Revenues – Regulated
millions of US dollars

	2012	2011	2010
Electric revenues	**$ 143.9**	$ 145.8	$ 110.9
Transmission pool revenues	**46.1**	40.2	38.0
Resale of purchased power	**14.5**	18.1	18.3
Operating revenues – regulated	**$ 204.5**	$ 204.1	$ 167.2

Electric Revenues

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.

Q4 Electric Sales Volumes

GWh	**2012**	2011	* 2010
Residential	**204**	196	155
Commercial	**193**	207	147
Industrial	**106**	91	84
Other	**3**	3	3
Total	**506**	497	389

* Excludes MPS which was acquired on December 21, 2010

Annual Electric Sales Volumes

GWh	**2012**	2011	* 2010
Residential	**786**	779	591
Commercial	**786**	846	594
Industrial	**425**	381	363
Other	**12**	11	12
Total	**2,009**	2,017	1,560

* Excludes MPS which was acquired on December 21, 2010

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

Q4 Electric Revenues
millions of US dollars

	2012	2011	* 2010
Residential	**$ 18.1**	$ 17.2	$ 13.6
Commercial	**13.7**	14.3	10.3
Industrial	**3.6**	2.6	2.9
Other	**2.1**	3.0	2.2
Total	**$ 37.5**	$ 37.1	$ 29.0

*Excludes MPS which was acquired on December 21, 2010

Annual Electric Revenues
millions of US dollars

	2012	2011	* 2010
Residential	**$ 68.4**	$ 68.1	$ 50.6
Commercial	**53.3**	56.2	39.4
Industrial	**13.0**	11.2	11.5
Other	**9.2**	10.3	9.4
Total	**$ 143.9**	$ 145.8	$ 110.9

*Excludes MPS which was acquired on December 21, 2010

Electric revenues increased $0.4 million to $37.5 million in Q4 2012 compared to $37.1 million in Q4 2011. For the year ended December 31, 2012, electric revenues decreased $1.9 million to $143.9 million in 2012 compared to $145.8 million in 2011. Highlights of the changes are summarized in the following table:

For the millions of US dollars	Three months ended December 31	Year ended December 31
Electric revenues – 2010		**$ 110.9**
Increased electric revenues due to acquisition of MPS and transmission rate changes, partially offset by unfavourable weather in 2011		34.9
Electric revenues – 2011	**$ 37.1**	**$ 145.8**
Decreased year-over-year primarily due to transmission rate changes in Bangor Hydro and stranded cost rate changes in MPS	(0.1)	(1.3)
Increased quarter-over-quarter sales volumes primarily due to favourable weather in Q4 2012; decreased year-over-year sales volumes primarily due to unfavorable weather in 2012	0.5	(0.6)
Electric revenues – 2012	**$ 37.5**	**$ 143.9**

Q4 Electric Revenue / MWh

	2012	2011	* 2010
Dollars per MWh	**$ 74**	$ 75	$ 75

*Excludes MPS which was acquired on December 21, 2010

Annual Average Electric Revenue / MWh

	2012	2011	* 2010
Dollars per MWh	**$ 72**	$ 72	$ 71

*Excludes MPS which was acquired on December 21, 2010

Transmission Pool Revenues and Expenses

These transmission pool expenses are recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income. Transmission pool revenues are recorded in "Operating revenues – regulated" in the Consolidated Statements of Income.

Transmission pool revenues and expenses are summarized in the following table:

For the millions of US dollars	Three months ended December 31			Year ended December 31	
	2012	2011	**2012**	2011	2010
Transmission pool revenues	**$ 11.0**	$ 8.8	**$ 46.1**	$ 40.2	$ 38.0
Transmission pool expenses	**5.1**	4.3	**19.4**	17.9	18.3
Net transmission pool revenues	**$ 5.9**	$ 4.5	**$ 26.7**	$ 22.3	$ 19.7

Maine Utilities' net transmission pool revenues increased $1.4 million to $5.9 million in Q4 2012 compared to $4.5 million in Q4 2011, and for the year ended December 31, 2012, net transmission pool revenues increased $4.4 million to $26.7 million compared to $22.3 million in 2011 primarily due to a higher level of investment in regionally funded transmission assets as well as favourable weather in the New England region.

Resale of Purchased Power and Regulated Fuel for Generation and Purchased Power

Bangor Hydro has several above-market power purchase contracts with generators in its service territory. The power purchased under these arrangements is resold at market rates significantly below the contract rates. 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 of $3.0 million as at December 31, 2012, is being amortized accordingly.

Resale of purchased power decreased $0.9 million to $3.8 million in Q4 2012 compared to $4.7 million in Q4 2011, and for the year ended December 31, 2012, resale of purchased power decreased $3.6 million to $14.5 million in 2012 compared to $18.1 million in 2011 primarily due to lower market rates for electricity in New England in 2012.

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"), a vertically-integrated utility and the sole provider of electricity on the island of Barbados, which serves approximately 134,000 customers and is regulated by the Fair Trading Commission, Barbados. The government of Barbados has granted BLPC a franchise to generate, transmit and distribute electricity on the island until 2028. BLPC owns approximately 239 MW of oil-fired generation, 81 kilometers of transmission facilities and 1,645 kilometers of distribution facilities. BLPC has a workforce of approximately 476 people. 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 rate base for 2012 is 10 percent. A fuel pass-through mechanism ensures fuel costs are recovered. Emera acquired a controlling interest in LPH on January 25, 2011.

- 50.0 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 approximately 19,000 customers. GBPC owns approximately 98 MW of oil-fired generation, 138 kilometers of transmission facilities and 860 kilometers of distribution facilities and has a workforce of approximately 142 people. GBPC is regulated by GBPA, which has granted it a licensed, regulated and exclusive franchise to generate, transmit and distribute electricity on the island until 2054. Effective July 1, 2012, GBPC's approved regulated return on rate base for 2012 is 10 percent. A fuel pass-through mechanism ensures fuel costs are recovered. Emera acquired a controlling interest in GBPC on December 22, 2010.

- 15.3 percent indirect interest, through LPH, in St. Lucia Electricity Services Limited ("Lucelec"), a vertically-integrated regulated electric utility on the Caribbean island of St. Lucia. The investment in Lucelec is accounted for on the equity basis.

Review of 2012

Caribbean Utility Operations' Net Income

For the millions of US dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2012	2011	**2012**	2011	2010
Operating revenues – regulated	**$ 101.3**	$ 105.6	**$ 421.1**	$ 411.2	$ -
Regulated fuel for generation and purchased power	**61.5**	71.7	**264.8**	276.9	-
Operating, maintenance and general (1)	**26.1**	23.1	**94.3**	88.4	6.8
Property taxes (2)	**0.2**	0.3	**1.5**	1.5	-
Depreciation and amortization	**7.3**	5.3	**30.2**	22.8	-
Total operating expenses	**95.1**	100.4	**390.8**	389.6	6.8
Income from operations	**6.2**	5.2	**30.3**	21.6	(6.8)
Income from equity investment	**0.5**	0.7	**1.7**	2.9	4.5
Other income (expenses), net	**4.9**	0.3	**7.7**	35.9	19.1
Interest expense, net	**2.6**	2.2	**9.3**	8.7	-
Income before provision for income taxes	**9.0**	4.0	**30.4**	51.7	16.8
Income tax expense (recovery)	**0.3**	0.4	**1.5**	0.7	-
Net income	**8.7**	3.6	**28.9**	51.0	16.8
Non-controlling interest in subsidiaries	**(1.9)**	(0.6)	**(5.7)**	(3.8)	2.2
Contribution to consolidated net income – USD	**$ 6.8**	$ 3.0	**$ 23.2**	$ 47.2	$ **19.0**
Contribution to consolidated net income – CAD	**$ 6.7**	$ 3.1	**$ 23.2**	$ 46.8	$ **19.8**
Contribution to consolidated earnings per common share – CAD	**$ 0.05**	$ 0.03	**$ 0.19**	$ 0.39	$ 0.17
Net income weighted average foreign exchange rate – CAD/USD	**$ 0.99**	$ 1.03	**$ 1.00**	$ 0.99	$ 1.04

(1) 2010 Operating maintenance and general costs comprise costs associated with the acquisition of a controlling interest in GBPC.

(2) Included in Provincial, state and municipal taxes on the Consolidated Statements of Income.

Caribbean Utility Operations' USD contribution to consolidated net income increased by $3.8 million to $6.8 million in Q4 2012 compared to $3.0 million in Q4 2011. For the year ended December 31, 2012, Caribbean Utility Operations' USD contribution to consolidated net income decreased by $24.0 million to $23.2 million compared to $47.2 million in 2011. 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 – 2010			**$**	**19.0**
Gain on initial investment in LPH recorded in 2010				(22.4)
Gain on acquisition of controlling interest in LPH in 2011				28.7
GBPC acquisition-related costs recorded in 2010				6.8
Increased income from increased investments in LPH and GBPC				9.5
Increased income due to regulatory deferral in GBPC				4.6
Other				1.0
Contribution to consolidated net income – 2011	**$**	**3.0**	**$**	**47.2**
Increased electric margin primarily due to GBPC's rate structure changes; year-over-year also increased due to an increased investment in LPH as of January 25, 2011		4.1		15.9
Increased OM&G expenses quarter-over-quarter primarily due to business development activities; year-over-year also increased primarily due to transitional costs associated with the new generation in GBPC		(3.0)		(5.9)
Increased non-controlling interest primarily due to increased earnings in GBPC		(1.3)		(1.8)
Increased other income net, quarter-over-quarter due primarily to recognition of a regulatory asset in GBPC; year-over-year also decreased primarily due to a $28.7 million gain on increased investment in LPH as of January 25, 2011		4.6		(28.2)
Other		(0.6)		(4.0)
Contribution to consolidated net income – 2012	**$**	**6.8**	**$**	**23.2**

Caribbean Utility Operations' CAD contribution to consolidated net income increased by $3.6 million to $6.7 million in Q4 2012 compared to $3.1 million in Q4 2011. Year-over-year Caribbean Utility Operations' CAD contribution to consolidated net income decreased by $23.6 million to $23.2 million compared to $46.8 million in 2011. The impact of a weaker USD, quarter-over-quarter decreased CAD earnings by $0.2 million for the three months ended December 31, 2012. The impact of a stronger USD year-over-year increased CAD earnings by $0.4 million compared to 2011.

Operating Revenues – Regulated

Caribbean Utility Operations operating revenues – regulated include sales of electricity and other services as summarized in the following table:

Q4 Operating Revenues – Regulated
millions of US dollars

		2012		2011
Electric revenues – base rates	**$**	**38.9**	$	36.8
Fuel charge		**61.5**		68.0
Total electric revenues		**100.4**		104.8
Other revenues		**0.9**		0.8
Operating revenues – regulated	**$**	**101.3**	$	105.6

Annual Operating Revenues – Regulated
millions of US dollars

		2012		2011
Electric revenues – base rates	**$**	**157.6**	$	148.9
Fuel charge		**260.6**		259.3
Total electric revenues		**418.2**		408.2
Other revenues		**2.9**		3.0
Operating revenues – regulated	**$**	**421.1**	$	411.2

Electric Revenues

Electric sales volume is primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal, with Q3 being the strongest period, reflecting warmer weather.

Q4 Electric Sales Volumes
GWh

	2012	2011
Residential	**99**	97
Commercial	**178**	180
Industrial	**19**	24
Other	**6**	6
Total	**302**	307

Annual Electric Sales Volumes
GWh

	2012	2011
Residential	**400**	385
Commercial	**721**	701
Industrial	**87**	92
Other	**23**	22
Total	**1,231**	1,200

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

Q4 Electric Revenues
millions of US dollars

		2012		2011
Residential	**$**	**30.8**	$	32.2
Commercial		**61.1**		61.2
Industrial		**6.8**		4.7
Other		**1.7**		6.7
Total	**$**	**100.4**	$	104.8

Annual Electric Revenues
millions of US dollars

		2012		2011
Residential	$	**127.3**	$	124.6
Commercial		**248.8**		239.8
Industrial		**31.2**		31.7
Other		**10.9**		12.1
Total	$	**418.2**	$	408.2

Electric revenues decreased $4.4 million to $100.4 million in Q4 2012 compared to $104.8 million in Q4 2011. For the year ended December 31, 2012, electric revenues increased $10.0 million to $418.2 million compared to $408.2 million in 2011. Highlights of the changes are summarized in the following table:

For the millions of US dollars		Three months ended December 31		Year ended December 31
Electric revenues – 2011	**$**	**104.8**	**$**	**408.2**
Increased year-over-year due to the increased investment in LPH as of January 25, 2011		-		17.9
Increased primarily due to changes in GBPC rate structure		2.1		2.3
Decreased fuel charge primarily due to lower temporary generation costs and improved plant performance in GBPC		(6.5)		(9.8)
Other		-		(0.4)
Electric revenues – 2012	**$**	**100.4**	**$**	**418.2**

Q4 Average Electric Revenue/MWh

		2012		2011
Dollars per MWh	**$**	**333**	$	342

Annual Average Electric Revenue/MWh

		2012		2011
Dollars per MWh	**$**	**340**	$	340

Electric Margin

Caribbean Utility Operations distinguishes revenues related to the recovery of fuel costs through the fuel charge from revenues related primarily to the recovery of non-fuel costs (“base rates”). Prior to July 1, 2012, GBPC’s base rate included the recovery of the first $20 USD/barrel of oil with any costs in excess of $20 USD/barrel recovered through the fuel charge.

Effective July 1, 2012, the GBPA approved a new regulatory structure whereby all the fuel costs are recovered through the fuel charge and the base rate is intended to recover GBPC’s operating expenses, depreciation, and return on capital invested which is consistent with BLPC’s rate structure. Consequently, Caribbean Utility Operations’ electric margin and net income are influenced primarily by the base rates, whereas the fuel charge and fuel costs do not have a material effect on electric margin or net income.

In both BLPC and GBPC, customer classes contribute differently to the Company’s base rate revenue, with residential and commercial customers contributing more than industrials. Residential and commercial load is primarily affected by changes in weather and economic conditions, while industrial load is primarily affected by changes in the economic conditions.

Electric margin is summarized in the following table:

For the millions of US dollars	Three months ended December 31		Year ended December 31	
	2012	2011	**2012**	2011
Operating revenues – regulated	**$ 101.3**	$ 105.6	**$ 421.1**	$ 411.2
Less: Other revenues	**(0.9)**	(0.8)	**(2.9)**	(3.0)
Total electric revenues	**100.4**	104.8	**418.2**	408.2
Total electric revenues is broken down as follows:				
Electric revenues – base rate	**$ 38.9**	$ 36.8	**$ 157.6**	$ 148.9
Fuel charge	**61.5**	68.0	**260.6**	259.3
Total electric revenues	**100.4**	104.8	**418.2**	408.2
Regulated fuel for generation and purchased power (1)	**61.5**	71.7	**264.8**	276.9
Regulatory amortization (2)	**0.7**	(1.0)	**1.8**	(4.4)
Electric margin	**$ 38.2**	$ 34.1	**$ 151.6**	$ 135.7

(1) In Q4 2012, regulated fuel for generation and purchased power includes $ nil (2011 – $3.1 million) of temporary generation costs. For the year ended December 31, 2012, regulated fuel for generation and purchased power includes $3.7 million (2011 – $10.1 million) of temporary generation costs.
(2) Included in "Depreciation and amortization" on the Consolidated Statements of Income

Caribbean Utility Operations' electric margin increased $4.1 million to $38.2 million in Q4 2012 compared to $34.1 million in Q4 2011 primarily due to changes in GBPC's rate structure, partially offset by reduced sales resulting from the decline in economic activity in The Bahamas' and Barbados' economies. For the year ended December 31, 2012, electric margin increased $15.9 million to $151.6 million compared to $135.7 million in 2011 primarily due to the increased investment in LPH as of January 25, 2011 combined with changes in GBPC's rate structure, partially offset by reduced sales resulting from the decline in economic activity in The Bahamas' and Barbados' economies.

Q4 Average Electric Margin / MWh

	2012	2011
Dollars per MWh	**$ 127**	$ 111

Annual Average Electric Margin / MWh

	2012	2011
Dollars per MWh	**$ 123**	$ 113

The change in average electric margin per MWh primarily relates to the rate structure changes at GBPC effective July 2012.

Regulated Fuel for Generation and Purchased Power

Q4 Production Volumes

GWh

	2012	2011
Oil	**332**	339

Annual Production Volumes

GWh

	2012	2011
Oil	**1,343**	1,317

Q4 Average Fuel Costs/MWh

	2012	2011
Dollars per MWh	**$ 185**	$ 202

Annual Average Fuel Costs/MWh

	2012	2011
Dollars per MWh	**$ 194**	$ 203

Regulated fuel for generation and purchased power decreased $10.2 million to $61.5 million in Q4 2012 compared to $71.7 million in Q4 2011 primarily due to lower temporary generation costs and improved plant performance in GBPC as the new generation unit was in service and lower fuel costs. For the year ended December 31, 2012, regulated fuel for generation and purchased power decreased $12.1 million to $264.8 million compared to $276.9 million in 2011 primarily due to the lower temporary generation costs and improved plant performance in GBPC as the new generation unit went into service in Q3 2012 and lower fuel prices.

Fuel Recovery Mechanisms

BLPC

All BLPC fuel costs are passed to customers through the fuel clause adjustment fuel charge. Fair Trading Commission, Barbados has approved the calculation of the fuel charge, which is adjusted on a monthly basis.

GBPC

Until June 30, 2012, the current base rate included $20 USD per barrel of oil consumed by GBPC for generation of electricity. The amount by which actual fuel costs exceeded $20 USD dollars per barrel was recovered or rebated through the fuel charge, which was adjusted on a monthly basis. The methodology for calculating the amount of the fuel charge was approved by GBPA.

Effective July 1, 2012, all GBPC fuel costs are passed to customers through the fuel charge. The GBPA has approved the calculation of the fuel charge, which is adjusted on a monthly basis.

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.

On April 12, 2011, GBPA approved, as part of the fuel charge, 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 generating facility. The amount by which the actual cost of the temporary generation exceeds what has been recovered through the fuel charge has been recorded as a regulatory asset.

These regulatory deferrals are being amortized into income beginning July 1, 2012, as part of the GBPA rate structure changes.

Effective July 1, 2012, the GBPA approved the recovery of $18.3 million related to retired generation assets in future rates. The fair value of these assets was less than the carrying value at the time Emera acquired a controlling interest in GBPC. Therefore, $4.6 million was recognized through income in Q4 2012 and recorded as a regulatory asset. GBPC is expected to amortize this deferral into income beginning in 2016.

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.

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 re-gasified natural gas from the Canaport™ 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 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 accounted for on the equity basis.

Review of 2012

Pipelines' Net Income

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2012	2011	**2012**	2011	2010
Operating revenues – regulated	**$ 12.6**	$ 12.7	**$ 50.1**	$ 49.8	$ 49.0
Operating maintenance and general	**-**	0.1	**0.1**	0.1	(0.1)
Accretion (1)	**-**	-	**0.2**	0.1	0.1
Income from equity investment	**3.4**	3.6	**14.0**	14.4	15.7
Other income (expenses), net	**-**	(0.2)	**0.2**	0.2	1.4
Interest expense, net	**7.5**	7.6	**30.2**	30.2	30.6
Income before provision for income taxes	**8.5**	8.4	**33.8**	34.0	35.5
Income tax expense (recovery)	**1.5**	1.5	**5.9**	6.1	6.6
Contribution to consolidated net income	**$ 7.0**	$ 6.9	**$ 27.9**	$ 27.9	$ 28.9
Contribution to consolidated earnings per common share	**$ 0.06**	$ 0.06	**$ 0.22**	$ 0.23	$ 0.25

(1) Accretion is included in "Depreciation and amortization" on the Consolidated Statements of Income.

Pipelines' contribution to consolidated net income did not materially change overall in Q4 2012 compared to Q4 2011 or for the year ended December 31, 2012 compared to 2011.

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 25.0 percent (combined Canadian federal and provincial income tax rate).

SERVICES, RENEWABLES AND OTHER INVESTMENTS

Overview

Services, Renewables and Other Investments includes the following consolidated and non-consolidated investments:

Consolidated Investments

- Emera Energy Services, a physical energy business, purchases and sells natural gas and electricity, and provides related energy asset management services, to customers across northeastern North America.
- Bayside Power, a 290-MW gas-fired merchant electricity generating facility in Saint John, New Brunswick.
- Utility Services, two utility services contractors, providing utility construction services in Atlantic Canada and The Bahamas.
- ENL, focused on transmission investments related to a proposed 824-MW hydro-electric generating facility at Muskrat Falls in Labrador.

Non-Consolidated Investments – accounted for on the equity basis

- Emera's 49.0 percent investment in NWP, a 385-MW portfolio of wind energy projects in the northeastern United States.
- Emera's 19.6 percent investment in APUC, a growing renewable energy and regulated utility public company with assets across North America, traded on the Toronto Stock Exchange ("TSX") under the symbol "AQN". APUC actively invests in hydroelectric, wind and solar power facilities and sustainable utility distribution businesses.
- Emera's 50.0 percent joint venture ownership of Bear Swamp, a 600-MW pumped storage hydro-electric facility in northern Massachusetts.
- Other investments include a 37.6 percent investment in Atlantic Hydrogen Inc. ("AHI").

Review of 2012

Services, Renewables and Other Investments Net Income

For the millions of Canadian dollars (except per share amounts)	Three months ended December 31		Year ended December 31		
	2012	2011	**2012**	2011	2010
Trading and marketing margin	**$ (9.5)**	$ 4.5	**$ 17.8**	$ 22.9	$ 18.1
Electricity sales	**14.8**	22.7	**61.0**	82.3	100.5
Utility services	**17.9**	22.9	**66.5**	67.4	75.7
Total operating revenues – non-regulated	**23.2**	50.1	**145.3**	172.6	194.3
Non-regulated fuel for generation and purchased power	**11.1**	18.3	**44.5**	73.9	83.9
Non-regulated direct costs	**15.7**	20.4	**57.6**	59.9	62.3
Operating, maintenance and general	**9.3**	7.6	**32.9**	31.5	34.5
Depreciation and amortization	**1.3**	0.8	**3.6**	3.4	3.5
Total operating expenses	**37.4**	47.1	**138.6**	168.7	184.2
Income (loss) from operations	**(14.2)**	3.0	**6.7**	3.9	10.1
Income from equity investments	**(2.9)**	2.6	**1.6**	17.1	1.2
Other income (expenses), net	**10.2**	0.5	**27.9**	14.6	(1.4)
Interest expense, net	**-**	-	**0.8**	0.9	1.1
Income (loss) before provision for income taxes	**(6.9)**	6.1	**35.4**	34.7	8.8
Income tax expense (recovery)	**(4.5)**	0.7	**1.7**	8.3	0.2
Contribution to consolidated net income (loss)	**$ (2.4)**	$ 5.4	**$ 33.7**	$ 26.4	$ 8.6
After-tax derivative mark-to-market gain (loss)	**$ (15.9)**	$ (0.9)	**$ (9.7)**	$ (3.0)	$ (3.2)
Adjusted contribution to consolidated net income	**$ 13.5**	$ 6.3	**$ 43.4**	$ 29.4	$ 11.8
Contribution to consolidated earnings per common share – basic	**$ (0.02)**	$ 0.04	**$ 0.27**	$ 0.22	$ 0.08
Adjusted contribution to consolidated earnings per common share – basic	**$ 0.11**	$ 0.05	**$ 0.35**	$ 0.24	$ 0.10

Mark-to-Market Adjustments

Mark-to-market adjustments are related to Emera's HFT derivative instruments included in Trading and Marketing Net Margin and Electricity Sales. Mark-to-market adjustments are also included in income from equity investments related to business activities of Bear Swamp and NWP.

Mark-to-market losses increased $15.0 million to $(15.9) million in Q4 2012 compared to $(0.9) million in Q4 2011 and increased $(6.7) million to $(9.7) million for the year ended December 31, 2012 compared to $(3.0) million in 2011 due to refinements in the valuation methodology for certain multi-year natural gas purchase contracts, and the addition of NWP's financial power swaps resulting from Emera's investment in NWP in 2012.

Trading and Marketing Net Margin

Trading and marketing net margin is comprised of Emera Energy's purchases and sales of natural gas and electricity sales, related energy asset management services and mark-to-market adjustments.

Electricity Sales

Electricity sales are comprised of Bayside Power's electricity sales and mark-to-market adjustments. Bayside Power is contracted under a long-term purchase power agreement to sell its entire generation during the months of November through March to a regulated power utility.

Utility Services

Utility services are comprised of two utility services contractors, providing utility construction services in Atlantic Canada and The Bahamas.

Services, Renewables and Other Investments contribution to consolidated net income decreased by $7.8 million to net income of $(2.4) million in Q4 2012 compared to net income of $5.4 million in Q4 2011. For the year ended December 31, 2012, Services Renewables and Other Investments contribution to consolidated net income increased $7.3 million to $33.7 million compared to $26.4 million in 2011. 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 – 2010		**$ 8.6**
Operating revenues – non-regulated – see table below for highlights		(21.7)
Decreased non-regulated fuel for generation and purchased power due to lower natural gas prices		10.0
Decreased non-regulated direct costs due to changes in construction activity in Utility Services		2.4
Increased income from equity investments primarily due to a positive change in fair value of the net derivatives of Bear Swamp		15.9
Increased other income due to APUC subscription receipts gains		16.0
Increased income tax expense primarily due to an increase in partnership income included in income from equity investments and the taxable gain on APUC subscription receipts		(8.1)
Other		3.3
Contribution to consolidated net income – 2011	**$ 5.4**	**$ 26.4**
Operating revenues – non-regulated – see table below for highlights	(26.9)	(27.3)
Decreased non-regulated fuel for generation and purchased power primarily due to a planned maintenance outage at Bayside Power and lower natural gas prices	7.2	29.4
Decreased non-regulated direct costs primarily due to changes in construction activity in Utility Services	4.7	2.3
Decreased income from equity investments quarter-over-quarter primarily due to mark-to-market losses in NWP and an unplanned outage in Bear Swamp; decreased year-over-year also primarily due to decreased income in CPUV and in APUC as a result of unfavorable weather and lower sales respectively	(5.5)	(15.5)
Increased other income net, due to APUC subscription receipt gains and a gain on the sale of the CPUV investment	9.7	13.3
Decreased income tax expense quarter-over-quarter primarily due to an increase in loss before provision for income taxes; decreased year-over-year primarily due to foreign exchange losses, a higher foreign tax rate on NWP losses and the deferred tax impact of dividends recorded against the investment in APUC	5.2	6.6
Other	(2.2)	(1.5)
Contribution to consolidated net income – 2012	**$ (2.4)**	**$ 33.7**

Operating Revenues – Non-Regulated

Operating revenues – non-regulated decreased $26.9 million to $23.2 million in Q4 2012 compared to $50.1 million in Q4 2011. For the year ended December 31, 2012, operating revenues – non-regulated decreased $27.3 million to $145.3 million compared to $172.6 million in 2011. 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
Operating revenues – non-regulated – 2010		**$ 194.3**
Increased trading and marketing margin due to stronger energy marketing results		5.3
Decreased electricity sales primarily due to lower priced contracted energy sales at Bayside Power reflecting lower natural gas prices		(8.3)
Decreased Utility Services due to changes in construction activity		(8.3)
Increased net mark-to-market losses due primarily to a reversal of 2010 mark-to-market gains		(10.4)
Operating revenues – non-regulated – 2011	**$ 50.1**	**$ 172.6**
Increased trading and marketing margin primarily due to stronger energy marketing results	5.6	6.1
Decreased electricity sales primarily due to a planned maintenance outage and lower priced contracted energy sales at Bayside Power reflecting lower natural gas prices	(7.6)	(25.9)
Decreased Utility Services due to changes in construction activity	(5.0)	(0.9)
Increased net mark-to-market losses due primarily to refinements in the valuation methodology for certain multi-year natural gas purchase contracts	(19.9)	(6.6)
Operating revenues – non-regulated – 2012	**$ 23.2**	**$ 145.3**

Other Income, Net

Other income, net includes Emera's gains on APUC subscription receipts and the sale of investment in CPUV.

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 29.3 percent (combined Canadian federal and provincial) on its Canada sourced income.

Utility Services is subject to corporate income tax at the statutory rate of 29.3 percent (combined Canadian federal and provincial) on its Canada sourced income and its Bahamas sourced income is not subject to corporate income tax.

CORPORATE

Overview

Corporate includes interest revenue on intercompany financings and costs associated with corporate activities not directly associated with the operations of Emera's consolidated subsidiaries and investments. Corporate includes certain corporate-wide functions including executive management, strategic planning, treasury services, financial reporting, tax planning, business development and corporate governance.

Review of 2012

Corporate

For the millions of Canadian dollars	Three months ended December 31		Year ended December 31		
	2012	2011	**2012**	2011	2010
Revenue (1)	**$ 10.0**	$ 7.6	**$ 36.7**	$ 30.2	$ 30.6
Corporate costs	**6.5**	3.8	**26.1**	26.7	27.3
Interest expense	**9.3**	8.5	**37.3**	33.9	32.0
Income tax expense (recovery)	**(1.6)**	(4.1)	**(12.4)**	(16.5)	(14.0)
Preferred stock dividends	**-**	-	**11.1**	6.6	3.0
Contribution to consolidated net income	**$ (4.2)**	$ (0.6)	**$ (25.4)**	$ (20.5)	$ (17.7)

(1) Revenue consists of interest from Brunswick Pipeline and NWP; and preferred dividends from Brunswick Pipeline.

Corporate Costs

Corporate costs increased by $2.7 million to $6.5 million in Q4 2012 compared to $3.8 million in Q4 2011 due primarily to foreign exchange losses as well as increased resources and deferred compensation costs. Corporate costs did not materially change for the year ended December 31, 2012 compared to 2011.

Interest Expense

Interest expense did not materially change in Q4 2012 compared to Q4 2011. Interest expense increased $3.4 million to $37.3 million for the year ended December 31, 2012 compared to $33.9 million in 2011 primarily due to increased borrowings to fund business acquisitions.

Income Tax Recovery

Income tax recovery decreased by $2.5 million to $1.6 million in Q4 2012 compared to $4.1 million in Q4 2011 primarily due to changes in management's estimate of expected realization for certain deferred tax assets and decreased $4.1 million to $12.4 million for the year ended December 31, 2012 compared to $16.5 million in 2011 primarily due to a decrease in loss before the provision for income taxes and changes in management's estimate of expected realization for certain deferred tax assets.

Preferred Stock Dividends

Preferred stock dividends increased $4.5 million to $11.1 million for the year ended December 31, 2012 compared to $6.6 million in 2011 due to the issuance of preferred shares in June 2012.

OUTLOOK

Emera's strategy is focused on driving profitable growth by investing in its existing and new businesses, improving the reliability and cost of service, reducing emissions from the generation of electricity, and transmitting that cleaner energy to market. Emera continues to build its existing businesses and leverage its core strength in utilities to pursue acquisitions and greenfield development opportunities in electric or gas utilities in addition to assets active in electricity, generation and energy-related services.

NSPI

NSPI is expected to earn within its allowed rate of return in 2013. NSPI has experienced growth in capital assets of 25 percent since the end of 2009. This growth has largely been driven by the requirement to reduce Nova Scotia's reliance upon high carbon and GHG emitting sources of energy, and thus resulting in a significant investment in renewable energy sources. The effect of continued investments of this nature, when combined with lower contributions from the pulp and paper industry, has contributed to increasing power rates for customers. NSPI continues to focus on cost control, productivity and service improvements as well as making regulated investments in renewable energy and system reliability projects. NSPI filed an annual capital expenditure plan with the UARB of $337 million for 2013. NSPI continues to look for opportunities to reduce rate pressure for customers, and these efforts may result in focused reductions to NSPI's proposed 2013 capital spending. The Company expects to finance its capital expenditures with funds from operations and debt.

Maine Utility Operations

USD income from Maine Utility Operations is dependent on the timely recovery and the reasonable return on transmission and distribution investments. Two complaints, currently before the FERC, are seeking to lower the current allowed ROE of 11.14 percent on base transmission investments and could negatively affect Bangor Hydro's return on transmission investments. Bangor Hydro and MPS are focused on gaining efficiencies by fully integrating the operations in Maine. In 2013, Maine Utilities expect to invest approximately $96 million USD in its capital program, including approximately $54 million USD for major transmission projects.

Caribbean Utility Operations

Growth in income from Caribbean Utility Operations is dependent on earning a reasonable return on new capital investments and ongoing management of operating costs. BLPC is undertaking an operating cost control program and has initiated an integrated resource planning process to optimize Barbados' short and long-term electricity requirements. The integrated resource plan will evaluate various generation technologies and fuel sources to provide the most reliable and efficient solution to customers.

LPH, consistent with its growth strategy, will evaluate opportunities for synergistic energy investments within the Caribbean region. With the investment in the new 52-MW West Sunrise Plant in 2012, GBPC will continue its efforts to improve the efficiency of its operations and evaluate opportunities to reduce the island's dependence on oil as its primary fuel source for generation of electricity. Caribbean Utility Operations plans to invest approximately $54 million USD in total capital programs in 2013.

Pipelines

Income from Pipelines is predominately 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 dependent on energy trading margins, construction activity, investment in renewable generation and transmission and distribution projects, and the continued success of Emera's partnership with APUC. Construction activity in Utility Services is project based.

ENL's subsidiary, NSP Maritime Link Inc., has invested approximately $28.8 million, including AFUDC, in the estimated $1.52 billion development of the Maritime Link Project. It is finalizing project cost estimates and filed an application with the UARB in Nova Scotia on January 28, 2013 seeking approval of the project. Investment in project development costs will continue, with costs and AFUDC continuing to be capitalized during this period. The UARB is required to issue a decision on the Maritime Link Project within 180 days of the date of filing. If the project receives UARB support, NSP Maritime Link Inc. would finalize construction cost estimates and be expected to commence construction activities by late 2013 or early 2014.

The Labrador-Island Transmission Link Project is currently estimated to cost $2.6 billion. ENL is a partner with Nalcor in this project and expects to begin investing in the Labrador-Island Transmission Link Project in Q1 2013. Subject to certain conditions, which are expected to be met in Q2 2013, ENL has an ongoing equity investment opportunity in the Labrador-Island Transmission Link Project.

Both projects are scheduled to be in service in 2017.

Corporate

Corporate is comprised of intercompany financing revenues, corporate interest expense and other corporate activities. Corporate's contribution to consolidated net income is expected to be lower in 2013 as business growth leads to increased interest expense.

LIQUIDITY AND CAPITAL RESOURCES

The Company generates cash primarily through its regulated 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, where applicable, after giving effect to the dividend payment.

Consolidated Cash Flow Highlights

Significant changes in the statements of cash flows between the years ended December 31, 2012 and 2011 include:

Year ended December 31 millions of Canadian dollars	**2012**	2011	$ Change 2012 versus 2011
Cash and cash equivalents, beginning of period	**$ 76.9**	$ 7.3	$ 69.6
Provided by (used in):			
Operating activities	**397.6**	399.5	(1.9)
Investing activities	**(919.4)**	(660.8)	(258.6)
Financing activities	**525.0**	331.4	193.6
Effect of exchange rate changes on cash and cash equivalents	**(2.6)**	(0.5)	(2.1)
Cash and cash equivalents, end of period	**$ 77.5**	$ 76.9	$ 0.6

Operating Cash Flows

Net cash provided by operating activities decreased $1.9 million to $397.6 million for the year ended December 31, 2012 compared to $399.5 million in 2011. Excluding a $90 million voluntary pension contribution in 2012, net cash provided by operating activities increased $88.1 million compared to 2011. The increase was due to higher cash earnings of $61.4 million and a reduction in the investment in non-cash working capital of $26.7 million.

In addition to the minimum contribution required by legislation, NSPI made an additional contribution of $90.0 million to its defined benefit pension plan on December 28, 2012. This contribution improved the funded status of the defined benefit pension plan. This pension payment is fully tax deductible, with cash tax savings of $31.1 million for the year ended December 31, 2012.

Investing Cash Flows

Net cash used in investing activities increased $258.6 million to $919.4 million for the year ended December 31, 2012 compared to $660.8 million in 2011. The increase was primarily due to Emera's investment in NWP and a $150.0 million USD loan to NWP, changes in restricted cash, partially offset by lower capital expenditures, proceeds from the sale of CPUV and the acquisition of LPH in 2011.

Capital expenditures for the year ended December 31, 2012, including AFUDC, were approximately $491 million and included:

- $284 million in NSPI;
- $68 million in Maine Utility Operations;
- $60 million in Caribbean Utility Operations; and
- $79 million in Services, Renewables and Other Investments.

Financing Cash Flows

Net cash provided by financing activities increased $193.6 million to $525.0 million for the year ended December 31, 2012 compared to $331.4 million in 2011. The increase was due to long-term debt issuances by NSPI, Bangor Hydro, GBPC and BLPC and proceeds from Emera's preferred share Series C issuance in June 2012 and common share issuance in December 2012, partially offset by the repayment of debt and credit facilities, higher dividend payments in 2012 and proceeds from a common share issuance in 2011.

Working Capital

As at December 31, 2012, Emera's cash and cash equivalents were $77.5 million (2011 – $76.9 million) and Emera's working capital was $349.4 million (2011 – $334.4 million). Of the $77.5 million of cash and cash equivalents held at December 31, 2012, $24.2 million is held by Emera's foreign subsidiaries. Emera is unaware of any significant restrictions on the repatriation of these funds, although a portion is considered permanently invested in these foreign subsidiaries.

Emera's future liquidity and capital needs will be predominately for working capital requirements and capital expenditures throughout the businesses, as well as acquisitions, dividends and debt servicing. Working capital is financed through internally generated cash flows and short-term credit facilities.

Contractual Obligations

As at December 31, 2012, commitments for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2013	2014	2015	2016	2017	Thereafter	Total
Long-term debt	$ 437.0	$ 319.7	$ 79.0	$ 255.6	$ 562.9	$ 1,981.7	$ 3,635.9
Purchased power (1)	151.2	155.2	153.3	119.3	115.7	1,157.5	1,852.2
Coal, biomass, oil and natural gas supply	126.8	69.8	21.2	17.3	-	-	235.1
Pension and post-retirement obligations (2)	33.0	36.4	72.1	62.8	26.8	629.0	860.1
Asset retirement obligations	1.3	1.6	1.1	5.2	2.1	335.9	347.2
Interest payment obligations (3)	177.2	156.3	143.3	136.9	127.8	1,994.6	2,736.1
Transportation (4)	55.6	34.5	19.8	4.6	2.0	9.4	125.9
Long-term service agreements (5)	30.2	22.8	21.4	16.1	12.7	35.0	138.2
Capital projects	70.4	3.0	4.0	-	-	-	77.4
Leases (6)	3.4	3.3	3.3	2.8	2.6	13.5	28.9
Other	25.3	0.5	0.5	0.5	0.5	0.5	27.8
	$ 1,111.4	$ 803.1	$ 519.0	$ 621.1	$ 853.1	$ 6,157.1	$ 10,064.8

(1) Purchased power: annual requirement to purchase 20 - 100 percent of electricity production from independent power producers.

(2) Pension and post-retirement obligations: Defined benefit funding contractual obligations were determined based on funding requirements and assuming pension accruals cease as at December 31, 2012. Credited service and earnings are assumed to be crystallized as at December 31, 2012. The Company contractual obligations for post-retirement (non-pension) benefits assumes members must be age 55 or over as at December 31, 2012 to be eligible. As the defined benefit pension plans currently undergoes regular reviews to revise contribution requirements and members are still accruing service under the plans, actual future contributions to the plans will differ from the amounts shown.

(3) Interest payment obligations are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect as at December 31, 2012.

(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, maintenance of certain generating equipment, and services related to a generation facility and wind operating agreements.

(6) Leases: operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

Forecasted Gross Consolidated Capital Expenditures

For the year ended December 31, 2013, forecasted gross consolidated capital expenditures are as follows:

millions of Canadian dollars	NSPI	Maine Utility Operations	Caribbean Utility Operations	Services Renewables and Other investments	Corporate	Total
Generation	$ 129.0	$ -	$ 40.7	$ 1.5	$ -	$ 171.2
Transmission	79.0	53.7	0.7	317.0	-	450.4
Distribution	73.0	17.2	9.9	-	-	100.1
Facilities, equipment, vehicles, and other	56.0	24.2	3.0	22.5	4.0	109.7
	$ 337.0	$ 95.1	$ 54.3	$ 341.0	$ 4.0	$ 831.4

Significant Individual Capital Projects

As at December 31, 2012, the individually significant capital projects are as follows:

millions of Canadian dollars	Nature of Project	Pre-2013 Spending	2013 Forecast	Post-2013 Forecast	Expected year of completion
NSPI					
Port Hawkesbury Biomass	Generation	$ 204.0	$ 5.0	$ -	2013
South Canoe	Generation	3.0	25.0	65.0	2014
LED Streetlight Conversion	Distribution	3.0	8.0	49.0	2019
Services, Renewables and other investments					
Maritime Link	Transmission	26.0	97.0	1,391.0	2017

Debt Management

In addition to funds generated from operations, 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. NSPI has an active commercial paper program for up to $400 million, of which outstanding amounts are backed 100 percent 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, 2012, 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 2017 – Revolver	$ 700	$ 313	$ 387
NSPI – Operating credit facility	June 2017 – Revolver	500	299	201
Bangor Hydro – in USD – Operating credit facility	September 2013 – Revolver	80	19	61
Other – in USD – Operating credit facilities	Various	31	12	19

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. Emera's significant covenants are listed below:

	Financial Covenant	Requirement	As at December 31, 2012
Emera			
Syndicated credit facility	Debt to capital ratio	Less than or equal to 0.70 to 1	0.58
NSPI			
Syndicated credit facility	Debt to capital ratio	Less than or equal to 0.65 to 1	0.61

Emera

On August 17, 2012, Emera extended the maturity of its $700 million committed syndicated revolving bank line of credit from June 2015 to June 2017, with no change in terms from the prior agreement.

Emera's base shelf prospectus expired in June 2012. Emera intends to file a base shelf prospectus in 2013. Emera has debt maturities of $338.4 million in 2013 and intends to refinance with either short-term credit facilities or long-term financing.

NSPI

On August 17, 2012, NSPI extended the maturity of its $500 million committed syndicated revolving bank line of credit from June 2015 to June 2017, with no change in terms from the prior agreement.

On March 6, 2012, NSPI completed the issuance of $250 million Series Y Medium-Term Notes. The Series Y Notes bear interest at a rate of 4.15 percent per annum until March 6, 2042. The net proceeds of the note offering were used to repay short-term borrowings and for general corporate purposes.

NSPI's base shelf prospectus expired in June 2012. NSPI intends to file a base shelf prospectus in 2013. NSPI has debt maturities of $300 million in 2013 and intends to refinance with either short-term facilities or accessing the long-term debt markets.

Maine Utility Operations

On January 31, 2012, Bangor Hydro completed the issuance 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 January 1, 2013, MPS renewed its existing $10 million USD revolving credit facility, with a new expiration date of September 30, 2013, with no change in terms from the prior agreement.

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 were used to partially finance the construction of a 52-MW power plant on Grand Bahama Island that is now complete and in service. 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 commencing October 25, 2012.

On February 9, 2012, LPH entered into a secured credit agreement with The Bank of Nova Scotia in the amount of USD $14.2 million. The proceeds of the credit agreement were used to partially finance the purchase of a 19.1 percent interest in Lucelec from a wholly-owned subsidiary of Emera. The credit agreement bears interest at a rate of the three month LIBOR plus 1.05 percent and is repayable in six equal, consecutive semi-annual installments over a three year period. The payments commence six months after the initial drawdown. LPH has provided a cash deposit of $14.2 million ($28.4 million Barbadian dollars) and an unlimited guarantee as security for the credit agreement.

Credit Ratings

Emera

On March 30, 2012, Standard and Poor's Rating Services ("S&P") affirmed its BBB+ rating for Emera, but revised its outlook to negative from stable citing increased regulatory risk due to capital expenditure requirements related to federal and provincial energy policies.

On April 3, 2012, Dominion Bond Rating Service ("DBRS") confirmed its BBB (high) rating for Emera, but changed its trend to negative from stable citing concerns over non-consolidated debt metrics.

On December 14, 2012, DBRS confirmed its BBB (high) rating for Emera and changed its trend to stable from negative citing expectations that Emera will continue to improve its non-consolidated debt metrics.

Emera's credit ratings issued by DBRS and S&P are as follows:

	DBRS	S&P
Long-term corporate	N/A	BBB+
Senior unsecured debt	BBB (high)	BBB

NSPI

On March 30, 2012, S&P affirmed its BBB+ rating for NSPI, but revised its outlook to negative from stable citing increased regulatory risk due to capital expenditure requirements related to federal and provincial energy policies.

On March 28, 2012, DBRS confirmed its A (low) with stable trend rating for NSPI.

NSPI's credit ratings issued by DBRS and S&P are as follows:

	DBRS	S&P
Corporate	N/A	BBB+
Senior unsecured debt	A (low)	BBB+

Bangor Hydro, MPS, BLPC and GBPC have no public debt, and accordingly have no requirement for public credit ratings. These utilities believe that their credit facilities provides adequate access to capital to support current operations and a base level of capital expenditures. For additional capital needs, these utilities expect to have sufficient access to competitively priced funds in the unsecured debt market.

Share Capital

Emera

As at December 31, 2012, Emera had 130.98 million (2011 – 122.83 million) common shares issued and outstanding. For the year ended December 31, 2012, 8.15 million (2011 – 8.21 million) common shares were issued for net proceeds of $258.7 million (2011 – $247.2 million).

On December 14, 2012, Emera completed an offering of 5,905,250 common shares, including the exercise of the over-allotment option of 770,250 common shares, at $34.10 per common share, for gross proceeds of $201.4 million and net proceeds of approximately $193.2 million.

As at December 31, 2012, Emera had 16.0 million (2011 – 6.0 million) preferred shares issued and outstanding.

On June 7 2012, Emera issued ten million 4.10 percent Cumulative Six-Year Rate Reset First Preferred Shares, Series C ("First Preferred Shares, Series C"). The First Preferred Shares, Series C were issued at $25.00 per share for gross proceeds of $250.0 million and net proceeds of $244.9 million. The net proceeds of the share offering were used to repay short-term borrowings and for general corporate purposes.

Caribbean Utility Operations

On January 16, 2013, GBPC issued thirty-two thousand non-voting cumulative redeemable perpetual variable preferred shares at $1,000 Bahamian per share for gross proceeds of $32.0 million Bahamian and net proceeds of $30.9 million Bahamian. The net proceeds of the share offering were used to repay intercompany loans with Emera for construction of the West Sunrise Plant.

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 2013 for defined benefit pension plans is expected to be in the range of $44.1 million to $59.2 million (2012 – $ 163.2 million actual, which included a $90.0 million additional contribution by NSPI). All pension plan contributions are tax deductible and will be funded with cash from operations.

In addition to the minimum contribution required by legislation, NSPI made an additional contribution of $90.0 million to its defined benefit pension plan on December 28, 2012. This contribution will improve the funded status of its defined benefit pension plan.

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 $7.1 million for 2013 (2012 – $6.9 million actual).

OFF-BALANCE SHEET ARRANGEMENTS

Defeasance

Upon privatization of the former provincially owned NSPC in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide principal and interest streams to match the related defeased debt, which at December 31, 2012 totaled $0.8 billion. The securities are held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), an affiliate of the Province of Nova Scotia. Approximately 67 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.

Under the privatization agreements, NSPI administers the defeasance cash flows and obligations pursuant to a Management and Administration Agreement. All of the NSPFC bank accounts are included in NSPI's pool of bank accounts under a mirror netting agreement and therefore, from time to time, if any cash accumulates in the NSPFC bank account it is available as an offset until that cash is required to service the defeased NSPC debt.

Guarantees and Letters of Credit

Emera had the following guarantees and letter of credits as at December 31, 2012:

- NSPI has provided a limited guarantee for the indebtedness of Renewable Energy Services Ltd. ("RESL") under a $23.5 million loan agreement between RESL and a third party lender. As at December 31, 2012, RESL's indebtedness under the loan agreement was $20.8 million. NSPI holds a security interest in the present and future assets by RESL in connection with a wind energy project at Point Tupper, Nova Scotia.

- 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 $5.1 million USD. As at December 31, 2012, the fair value of the PPA was positive.

- Standby letters of credit in the amount of $7.3 million USD 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.

- Emera has provided standby letters of credit in the amount of $3.3 million USD for the benefit of third parties that have extended credit to subsidiaries of NWP. These letters of credit typically have a one year term and are renewed annually as required.

- A standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2013 and is renewed annually. The amount committed as at December 31, 2012 was $28.7 million.

- A standby letter of credit to secure obligations under an unfunded pension plan in Bangor Hydro. The letter of credit expires in October 2013 and is renewed annually. The amount committed as at December 31, 2012 was $2.2 million USD.

- A standby letter of credit in connection with a precedent transmission line agreement between Bangor Hydro and two other parties. The letter of credit expires in October 2013. The amount committed as at December 31, 2012 was $1.8 million USD.

- 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. The letters of credit expire in November 2013.

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

TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera provides energy and construction related services and enters into transactions with its associated and other related companies on terms similar to those offered to non-related parties.

If these transactions are eliminated on consolidation, they are not disclosed as related party transactions. Below are transactions between Emera and its associated companies that are not eliminated on consolidation:

For the millions of Canadian dollars				Year ended December 31
			2012	2011
	Nature of Service	**Presentation**		
Sales:				
EES	Net sale of natural gas	Operating revenue - non regulated	**$ 12.5**	$ 1.1
EES	Sale of power	Operating revenue - non regulated	**0.5**	-
Utility services	Maintenance and construction services	Operating revenue - non regulated	**19.0**	22.7
Utility services	Construction, operations management and engineering services	Operating revenue - non regulated	**14.9**	3.2
Purchases:				
NSPI	Net purchase of natural gas	Fuel for generation and purchased power	**$ 12.5**	$ 1.1
NSPI	Purchase of power	Fuel for generation and purchased power	**0.5**	-
NSPI	Maintenance services	OM&G	**1.4**	6.1
NSPI	Construction services	Property plant and equipment	**17.6**	16.6
GBPC	Maintenance services	OM&G	**6.2**	-
GBPC	Construction services	Property plant and equipment	**8.7**	3.2

Following are transactions between Emera and its equity investments:

M&NP

In the ordinary course of business, Emera purchased natural gas transportation capacity from M&NP, an investment under significant influence of the Company, totaling $35.6 million (2011 – $47.3 million) for the year ended December 31, 2012. 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, 2012, the amount payable to the related party was $2.9 million (December 31, 2011 – $3.3 million), and is under normal interest and credit terms.

Emera has a loan receivable from M&NP bearing interest at 1 percent per annum with maturity of November 30, 2019. As at December 31, 2012, the loan balance was $2.5 million and is recognized as “Due from related parties” on Emera’s Consolidated Balance Sheets (December 31, 2011– $2.8 million).

Lucelec

On January 31, 2012, a wholly-owned subsidiary of Emera sold its 19.1 percent interest in Lucelec at book value to LPH, a subsidiary owned 80.0 percent at that time by Emera, for $26.2 million ($26.1 million USD) effective January 1, 2012.

First Wind

On February 17, 2010 Bangor Hydro entered into a 20-year contract commencing July 2011 for 20 percent of the capacity and energy generated from a 60 MW wind facility in Maine, as directed by the MPUC. The wind facility is a wholly-owned subsidiary of NWP. The net amount paid to NWP is minimal for the period as the investment in First Wind occurred on June 15, 2012. Losses (or gains) from the resale of capacity and energy acquired under the contract are recoverable by Bangor Hydro in its stranded cost rates.

On June 15, 2012, Emera, through a wholly-owned subsidiary, signed a credit agreement with a wholly-owned subsidiary of NWP of which Emera holds a 49 percent interest, for a $150 million USD loan, bearing interest at 8 percent per annum with interest payable semi-annually and maturing on the earlier of Emera transferring its ownership interest in NWP or June 15, 2017. If on any date on which interest is due the borrower does not have sufficient free cash to make the scheduled interest payment, the borrower is entitled to satisfy its interest payment obligation by adding the amount of any shortfall to the outstanding principal of the loan. Any such amount that is added to the principal of the loan bears interest at a rate of 12 percent per annum, with interest payable semi-annually on the same dates as the interest payments on the $150 million USD principal amount referred to above. As at December 31, 2012, the loan balance was $149.2 million ($150 million USD) and is recognized as “Due from related parties” on Emera’s Consolidated Balance Sheets (December 31, 2011 – nil). As at December 31, 2012, the interest receivable on the loan was $6.5 million ($6.6 million USD) and is recognized as “Other assets” on Emera’s Consolidated Balance Sheets (December 31, 2011 – nil).

On June 15, 2012, Emera Energy Services, a wholly-owned subsidiary of Emera, signed an agreement with NWP to provide energy management services for an annual fee of $0.5 million.

CPUV

On December 21, 2012, Emera sold its 49.999 percent direct ownership interest in CPUV to APUC for $38.8 million resulting in an after-tax gain of $2.2 million. The pre-tax gain is recognized in “Other income, (expenses), net” on Emera’s Statements of Income. This transaction was measured at the exchange amount.

DIVIDENDS AND PAYOUT RATIOS

Emera Incorporated’s common dividend rate was $1.36 ($0.3375 per quarter in Q1, Q2 and Q3 and $0.3500 in Q4) per common share for the year ended December 31, 2012 and $1.31 ($0.3250 per quarter in Q1, Q2 and Q3 and $0.3375 in Q4) per common share for the year ended December 31, 2011, representing a payout ratio of approximately 76.3 percent in 2012 and 65.8 percent for the year ended December 31, 2011.

On September 28, 2012, Emera’s Board of Directors approved an increase in the annual common dividend rate from $1.35 to $1.40, and accordingly declared a quarterly dividends of $0.3500 per common share.

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.

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 in the hedged item when the hedged item is settled. 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 or 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 2012**		December 31 2011
Derivative instrument assets (current and other assets)	**$**	**6.7**	$	5.7
Derivative instrument liabilities (current and long-term liabilities)		**(8.3)**		(27.8)
Net derivative instrument assets (liabilities)	**$**	**(1.6)**	$	(22.1)

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	Year ended December 31 2012	2011
Operating revenues – regulated	**$ -**	$ 2.7
Non-regulated fuel for generation and purchased power	**(10.7)**	(7.0)
Income from equity investments	**2.1**	-
Other income (expenses), net	**-**	(0.3)
Effective net gains (losses)	**$ (8.6)**	$ (4.6)

The effectiveness gains (losses) reflected in the above table would be offset in net income by 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	Year ended December 31 2012	2011
Non-regulated fuel for generation and purchased power	**$ -**	$ (0.4)
Ineffective gains (losses)	**$ -**	$ (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 2012**	December 31 2011
Derivative instrument assets (current and other assets)	**$ 20.1**	$ 44.5
Regulatory assets (current and other assets)	**22.7**	46.3
Derivative instrument liabilities (current and long-term liabilities)	**(22.4)**	(46.3)
Regulatory liabilities (current and long-term liabilities)	**(20.1)**	(44.5)
Net asset (liability)	**$ 0.3**	$ -

Regulatory Impact Recognized in Net Income

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

For the millions of Canadian dollars	Year ended December 31 2012	2011
Regulated fuel for generation and purchased power	**$ (34.2)**	$ (21.3)
Net gains (losses)	**$ (34.2)**	$ (21.3)

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 2012**		December 31 2011
Derivative instruments assets (current and other assets)	**$**	**20.7**	$	16.7
Derivative instruments liabilities (current and long-term liabilities)		**(26.8)**		(14.7)
Net derivative instrument assets (liabilities)	**$**	**(6.1)**	$	2.0

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				Year ended December 31
		2012		2011
Non-regulated operating revenues	**$**	**16.1**	$	14.0
Other income (expenses), net		**-**		(0.1)
Net gains (losses)	**$**	**16.1**	$	13.9

Business Risks

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 regulatory risks, changes in environmental legislation, interest rate, commodity price risk, foreign exchange, commercial relationships, labour, weather, acquisition risk, credit, project development and construction risk, capital market and country risk.

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.

Regulatory Risk

The Company’s rate-regulated subsidiaries are subject to risk in the recovery of costs and investments in a timely manner. As cost-of-service utilities with an obligation to serve, NSPI, Bangor Hydro, MPS, BLPC, and GBPC must obtain regulatory approval to change electricity rates and/or riders from their respective regulators. Costs and investments can be recovered upon the respective regulator’s approval of the recovery in adjustments to rates and/or riders, which normally requires a public hearing process.

During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these subsidiaries and their respective regulators determine whether to allow recovery and to adjust rates based upon the subsidiaries’ evidence and any contrary evidence from other parties.

NSPI, Bangor Hydro, MPS, BLPC, and GBPC manage their regulatory risk through transparent regulatory disclosure, ongoing stakeholder consultation and multi-party engagement on aspects such as utility operations, fuel-related audits, rate filings and capital plans.

EBP entered into a 25 year firm service agreement with REC which was filed with the National Energy Board ("NEB"). The firm service agreement provides for predetermined toll increases after the fifth and fifteenth year of the contract. As a regulated Group II pipeline, the tolls of EBP are regulated by the NEB on a complaint basis. EBP is required to make copies of tariffs and supporting financial information readily available to interested persons. Persons who cannot resolve traffic, toll and tariff issues with EBP may file a complaint with the NEB. In the absence of a complaint, the NEB does not normally undertake a detailed examination of EBP's tolls.

Changes in Environmental Legislation

NSPI

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 audits completed to December 31, 2012.

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 ("GHG") emissions. This has been achieved by energy efficiency and conservation programs, increased use of natural gas, the addition of new renewable energy sources to the generation portfolio and partially as a result of decreased industrial load.

GHG 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.

On September 12, 2012, Environment Canada published the final regulations for the national carbon dioxide framework in the Canadian electricity sector, which apply to existing and new coal-fired electricity generation units.

NSPI will not likely be subject to the federal regulations, as the Nova Scotia Environment Department and Environment Canada have proposed an equivalency agreement, with input from NSPI. This process was initially proposed on March 19, 2012, when Environment Canada and the Nova Scotia Environment Department announced they would work toward an equivalency agreement on coal-fired electricity GHG regulations to avoid duplication of efforts to control GHG emissions.

In the equivalency agreement published in Canada Gazette I on September 14, 2012, provincial regulations would take precedence over federal regulations, provided provincial regulations achieve an equivalent emissions outcome. The equivalency agreement proposed by the Government of Canada and the Nova Scotia government would require reductions equivalent to or greater than the new federal regulations, but allow NSPI operational flexibility in the determination of the means of compliance. The equivalency agreement is expected to be finalized in 2013.

Nova Scotia's existing GHG regulations require reductions of 25 percent in GHG emissions in the electricity sector by 2020, compared to emissions in 2010. Based on the new federal regulations, a further reduction of 25 percent compared to 2010 emissions will be required by 2030. Discussions are underway with the Province of Nova Scotia with the intent to ensure consistency with the proposed federal regulations. NSPI is 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. 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. NSPI now meets the nitrogen oxide emission cap of 21,365 tonnes per year established by the Nova Scotia Government effective 2010.
NSPI is committed to meeting ever-reducing sulphur dioxide emission cap requirements through the use of a blend of net lower sulphur content solid fuel. These investments, combined with the purchasing of low sulphur coal, allow NSPI to meet the provincial air quality regulations.

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.

Interest Rate Risk

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures resulting in an exposure to interest rate risk. Emera 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. Emera has two interest rate hedging contracts outstanding as at December 31, 2012, fixing the variable interest rates on $22.6 million USD of Maine Public Utilities Financing Bank bonds at MPS.

Regulatory lag in a period of rising interest rates may have a negative effect on ROE rates. Rising interest rates may also negatively affect the economic viability of project development initiatives.

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.

<u>Coal/Petroleum Coke</u>

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, 2012 are as follows:

2013 – 74 percent
2014 – 39 percent
2015 – 14 percent
2016 – 9 percent

<u>Natural Gas</u>

NSPI has entered into multi-year contracts to purchase approximately 27,000 mmbtu of natural gas per day in 2013 and 2014. 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, 2012, amounts of natural gas volumes that have been economically and/or financially hedged are approximately as follows:

2013 – 91 percent
2014 – 38 percent

<u>Heavy Fuel Oil</u>

NSPI manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options, and forward contracts. For 2013 and 2014, 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 average of the previous month's spot market rate, and BLPC's fuel pricing is based on the three-day average market price.

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

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 in NSPI is measured and managed. In 2013, NSPI expects approximately 72 percent of its anticipated net fuel costs to be denominated in USD. Forward contracts to buy $212.0 million USD were in place as at December 31, 2012 at a weighted average rate of $1.0251, representing 59 percent of 2013's anticipated USD requirements. Forward contracts to buy $624.0 million USD in 2014 through 2017 at a weighted average rate of $1.0043 were in place as at December 31, 2012. These contracts cover 55 percent of anticipated USD requirements in these years. As at December 31, 2012, 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 €2.8 million were in place as at December 31, 2012 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 USD. Forward contracts to sell $53.8 million USD in 2013 were in place as at December 31, 2012 at an average rate of $1.0561 and sell $51 million USD in 2014 through 2017 at a weighted average rate of $1.0513. These contracts cover 95 percent of anticipated USD revenue inflows in 2013 and 22 percent of anticipated USD revenue inflows in 2014 through 2017.

Commercial Relationships Risk

NSPI

For the year ended December 31, 2012, NSPI's five largest customers contributed approximately 7.1 percent (2011 – 13.3 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 operational adjustments and cost management as well as the regulatory process. As discussed below, two large industrial customers were not operating for a large portion of 2012. However, the financial impact of this was deferred as approved by the UARB through the FCR mechanism.

In September 2011, a large industrial customer was granted creditor protection under the Companies' Creditors Arrangement Act ("CCAA") and suspended operations. On September 28, 2012, the customer's Plan of Arrangement pursuant to the CCAA process was finalized; the CCAA creditor protection ceased, and a new owner resumed a significant portion of the operations under a load retention tariff. Another large customer indefinitely idled their mill in June 2012.

The 2012 GRA Decision, approved by the UARB, provided for a FCR effective January 1, 2012, which allowed NSPI to defer any unrecovered contribution toward non-fuel expenses in 2012 related to both of these customers. The 2013 GRA settlement agreement, approved on December 21, 2012 by the UARB, allows recovery of the FCR from customers over a three-year period commencing January 1, 2013.

Brunswick Pipeline

Brunswick Pipeline has a 25 year firm service agreement with Repsol Energy Canada (“REC”). The pipeline was used solely in 2012 and 2011 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, 2012 the net investment in direct financing lease with Repsol was $491.9 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.

On March 14, 2012, Repsol was downgraded by Moody’s to Baa2 from Baa1. Subsequently, on June 12, 2012, Moody’s further downgraded Repsol from Baa2 to Baa3 and on June 29, 2012, Moody’s revised their outlook on Repsol from stable to negative. On April 19, 2012, Standard & Poor’s downgraded Repsol to BBB- from BBB, with a negative outlook. Subsequently on June 22, 2012, Standard & Poor’s revised their outlook on Repsol to stable from negative and affirmed their BBB- corporate credit rating. The rating agency actions have had no impact on the operations of the Canaport facility, nor REC’s fulfillment of its obligations under the firm service agreement to date.

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 55.7 percent (2011 – 46.5 percent) to Bayside Power’s electric revenues for the year ended December 31, 2012. 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 53 percent of the full-time and term employees at NSPI, BLPC, GBPC, Bangor Hydro, EUS, and MPS are represented by local unions.

On November 2, 2012, NSPI employees subject to the collective labour agreement voted to accept a new collective agreement which expires on March 31, 2015. NSPI’s prior collective agreement expired on March 31, 2012.

Approximately 15 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 and costs. 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.

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.

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.

Project Development and Construction Risk

ENL's planned investment in the development of the Maritime Link Project has risks commensurate with any large construction project. Risks related to such large projects include impact on costs of schedule delays and risk of cost overruns. Emera has deployed a robust project and risk management approach to this project, led by a team with extensive experience in large projects. There are also significant contractual terms in place protecting Emera and ENL from any exposure to cost overruns to either of Nalcor's projects and with Nalcor sharing in any cost overruns of the Maritime Link Project.

If Emera does not meet certain conditions relating to closing its financing, it could be subject to a $60 million penalty. Nalcor has agreed to pay $30 million of this obligation to Emera.

Capital Market Risk

Emera's utility operations and projects in development require significant capital investments in property, plant and equipment. Consequently, Emera is an active participant in the debt and equity markets. Any disruption in capital markets could have a material impact on Emera's ability to fund its operations. Capital markets are global in nature and are affected by numerous events throughout the world economy. Capital market disruptions could prevent Emera from issuing new securities or cause the Company to issue securities with less than ideal terms and conditions.

Country Risk

Operating revenues outside of Canada constituted 31 percent of Emera's total operating revenues. Emera's investments are currently in regions where the political and economic risk levels are considered by the Company to be acceptable. Emera's operations in some countries may be subject to the following risks: changes in the rate of economic growth, restrictions on the repatriation of income or capital exchange controls, inflation, the effect of global health, safety and environmental matters or economic conditions and market conditions, and change in financial policy and availability of credit. To mitigate this risk, Emera has a rigorous approval process for investment. In addition, a liquidity strategy is developed for all investments.

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, 2012 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”).

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, 2012.

There have been no changes in Emera or its consolidated subsidiaries’ ICFR during the period beginning on January 1, 2012 and ending on December 31, 2012, which have materially affected, or are reasonably likely to materially affect ICFR.

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, pension and other post-retirement employee benefits, unbilled revenue, useful lives for depreciable assets, goodwill impairment assessments, income taxes, asset retirement obligations, capitalized overhead and valuation of derivative instruments,. Actual results may differ from these estimates.

SIGNIFICANT ACCOUNTING POLICIES

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.

Emera has recorded $474.1 million of regulatory assets and $110.7 million of regulatory liabilities.

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 5.00 percent for 2012 (2011 – 5.50 percent) and Bangor Hydro's rate was 4.60 percent for 2012 (2011 – 5.60 percent). MPS' rate was 4.50 for 2012 (2011 – 5.40 percent) and GBPC's rate for 2012 was 5.00 percent (2011 – 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 6.75 percent for 2012 (2011 – 7.00 percent) for NSPI and 8.00 percent for 2012 and 2011 for Bangor Hydro. The assumed rate of return on plan assets for 2012 and 2011 was 8.50 percent for MPS and 5.50 percent for 2012 (2011 – 6.00 percent) for GBPC.

The reported benefit cost for 2012, based on management's best estimate assumptions, is $66.8 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 2012 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	2012	2011	2012	2011
Discount rate assumption	$(4.1)	$(3.9)	$4.2	$4.0
Asset return assumption	$(2.1)	$(2.0)	$2.1	$2.0

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. Utility Services 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, 2012, unbilled revenues amount to $143.2 million (2011 – $133.6 million) on a base of annual operating revenues of approximately $2,058.6 million (2011 – $2,064.4 million).

Property, Plant and Equipment

Property, plant and equipment represents 59.7 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.

Depreciation expense was $227.9 million for the year ended December 31, 2012 (2011 – $215.4 million).

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 were effective January 1, 2012, as approved by the UARB in the 2012 General Rate Decision.

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.

Goodwill arose on the acquisitions of GBPC, Bangor Hydro and MPS. At December 31, 2012, this goodwill had a total carrying amount of $193.5 million (December 31, 2011 – $197.7 million)

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.

Determining the fair market value of goodwill is susceptible to changes from period to period as assumptions about future cash flows are required.

Emera reviewed the carrying amount of goodwill and no goodwill impairments existed for the year ended December 31, 2012 or 2011.

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 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. 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.

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)	
	2012	2011	**2012**	2011	**2012**	2011
Thermal	**5.1 – 5.3%**	5.1 – 5.3%	**$142.8**	$142.8	**21 – 32**	21 – 32
Hydro	**5.1 – 5.3%**	5.1 – 5.3%	**127.6**	127.6	**20 – 50**	20 – 50
Wind	**5.1 – 5.2%**	5.1 – 5.2%	**27.4**	27.4	**17 – 24**	17 – 24
Combustion turbines	**5.1 – 5.3%**	5.1 – 5.3%	**8.4**	8.3	**5 – 34**	5 – 34
Transmission & distribution	**4.3 – 5.8%**	4.3 – 5.8%	**16.7**	30.4	**1 – 14**	1 – 14
Pipeline	**3.50%**	3.50%	**24.4**	24.6	**38**	38
			$347.3	$361.1		

As at December 31, 2012, the AROs recorded on the balance sheet were $95 million (2011 – $99.9 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $347.3 million, which will be incurred between 2012 and 2062. The majority of these costs will be incurred between 2032 and 2047.

Capitalized Overhead

As required by their respective regulators, NSPI, Bangor Hydro, MPS, GBPC and BLPC capitalize overhead costs that are not directly attributable to specific utility assets, but to the overall capital expenditure program. The methodology for the calculation of capitalized overhead is approved by their respective regulator. For the year ended December 31, 2012, $52.4 million (2011 – $58.1 million) of overhead costs were capitalized to capital assets. Any change in the methodology in the calculation and allocation of overhead costs could have a material impact on the amounts recognized as expenses versus assets.

Financial Instruments

Emera is required to determine the fair value of all derivatives except those which qualify for the normal purchase, normal sale exception. Fair value is the price that would be received for the sale of an asset or paid to transfer a liability in an orderly arms-length transaction between market participants at the measurement date. Fair value measurement 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.

Level Determinations and Classifications

Emera uses the Level 1, 2 and 3 classifications in the fair value hierarchy. The fair value measurement of a financial instrument is included in only one of the three levels and is based on the lowest level input significant to the derivation of the fair value. Fair values are determined, directly or indirectly, using inputs that are unobservable for the asset or liability. In limited circumstances, Emera may enter into commodity transactions involving non-standard features where market observable data is not available or contracts with terms that extend beyond five years.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

In July 2012, the Financial Accounting Standards Board ("FASB") issued an accounting standards update amending Accounting Standards Codification ("ASC") 350 to simplify how entities test indefinite-lived intangible assets for impairment and enhance the consistency of impairment testing among long-lived asset categories. The amendment permits an entity to first assess qualitative factors before determining whether it is necessary to calculate the indefinite-lived intangible asset's fair value during the annual impairment test. Under this amendment, an entity would not be required to calculate the fair value of the indefinite-lived asset unless the entity determines, based on the qualitative assessment, that there is more than 50 percent likelihood that the indefinite-lived intangible asset's fair value is less than its carrying amount. If an entity concludes that it is not more than 50 percent likely that the indefinite-lived intangible asset is impaired, the entity is not required to take any further action. If an entity concludes otherwise, it must perform the quantitative assessment and compare the fair value of the indefinite-lived intangible asset to its carrying amount. The amendment defines a number of events and circumstances for an entity to consider in conducting the qualitative assessment. Accounting Standards Update ("ASU") Number ("No.") 2012-02 is effective for impairment tests performed for fiscal years beginning after September 15, 2012; early adoption is permitted. The Company has decided to adopt this standard early; the new approach was used in its annual impairments testing as at October 1, 2012. Adoption of this standard did not have a material impact on the Company's financial statements.

In Q1 2012, Emera adopted ASU No. 2011-04. This ASU amended ASC 820 and achieved common fair value measurement and disclosure requirements between US GAAP and International Financial Reporting Standards ("IFRS"). The new accounting standard covers disclosure only and had no effect on the financial results of the Company.

In Q1 2012, Emera adopted ASU No. 2011-05. This ASU amended ASC 220 to improve the comparability, consistency and transparency of comprehensive income reporting. The new accounting standard covers disclosure only and had no effect on the financial results of the Company.

Future Accounting Pronouncements

Technical Corrections and Improvements - ASU No. 2012-04

In October 2012, the FASB issued an ASU amending certain ASC for technical corrections and improvements and conforming amendments related to fair value measurements (ASC 820). The amendments represent clarifications, corrections to unintended application of guidance and minor improvements to the ASCs that are not expected to have a significant effect on current accounting practice. The amendments to ASC 820 are intended to make the codification easier to understand and the guidance easier by eliminating inconsistencies and providing clarification. ASU No. 2012-04 is effective upon issuance for amendments that will not have transition guidance and for those amendments that are subject to transition guidance, fiscal periods beginning on or after December 15, 2012. The Company does not expect the adoption of this standard will have any impact on the financial statements.

Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, ASU No. 2011-11

In December 2011, the 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 arrangement 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.

Following an exposure draft issued in November 2012, the FASB decided to refine the scope of the disclosures to derivative instruments that are accounted for in accordance with Topic 815, Derivatives and Hedging. The Company is currently in compliance with this standard and therefore, does not expect the adoption of this standard will have any impact on the financial statements.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended millions of dollars (except per share amounts)	**Q4 2012**	Q3 2012	Q2 2012	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011
Operating revenues	**$ 512.9**	$ 476.4	$ 501.3	$ 568.0	$ 512.0	$ 496.1	$ 501.7	$ 554.6
Net income attributable to common shareholders	**42.7**	44.7	53.2	80.2	46.8	40.8	29.9	123.6
Earnings per common share – basic	**0.34**	0.36	0.43	0.65	0.38	0.33	0.24	1.06
Earnings per common share – diluted	**0.34**	0.36	0.43	0.64	0.38	0.33	0.24	1.03

Quarterly operating revenues and net income attributable to common shareholders are affected by seasonality. Q1 is 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 could be affected by items outlined in the Significant Items section and mark-to-market adjustments.

OPERATING STATISTICS (Unaudited)

FIVE-YEAR SUMMARY

Year ended December 31	**2012**	2011	2010	2009	2008
Electric energy sales (GWh)					
Residential	**5,372.2**	5,458.9	4,738.2	4,819.2	4,769.6
Commercial	**6,174.7**	6,562.3	5,584.4	3,694.4	3,721.1
Industrial	**2,678.7**	3,988.5	4,268.2	3,985.3	4,491.5
Other	**371.2**	347.0	620.1	1,166.9	652.2
Total electric energy sales	**14,596.8**	16,356.7	15,210.9	13,665.8	13,634.4
Sources of energy (GWh)					
Thermal – coal	**6,223.0**	6,848.0	7,838.7	8,177.3	9,008.9
– oil	**1,355.1**	1,070.8	36.1	306.9	340.7
– natural gas	**3,726.0**	4,304.7	4,183.0	2,141.4	1,257.9
Hydro	**828.0**	1,414.5	991.5	1,063.4	1,065.3
Wind	**256.0**	247.0	25.3	1.8	2.4
Purchases	**3,210.2**	3,518.3	2,987.4	2,846.1	2,874.5
Total generation and purchases	**15,598.3**	17,403.3	16,062.0	14,536.9	14,549.7
Losses and internal use	**1,001.5**	1,046.6	851.1	871.1	915.3
Total electric energy sold	**14,596.8**	16,356.7	15,210.9	13,665.8	13,634.4
Electric customers					
Residential	**702,738.0**	696,970.0	588,935.0	539,333.0	535,494.0
Commercial	**79,613.0**	79,817.0	61,620.0	51,768.0	54,461.0
Industrial	**2,521.0**	2,517.0	2,558.0	2,543.0	2,541.0
Other	**20,230.0**	10,446.0	9,422.0	9,155.0	9,064.0
Total electric customers	**805,102.0**	789,750.0	662,535.0	602,799.0	601,560.0
Capacity					
Generating nameplate capacity (MW)					
Coal fired	**1,243.0**	1,243.0	1,243.0	1,243.0	1,243.0
Dual fired	**350.0**	350.0	350.0	350.0	365.0
Gas turbines	**746.5**	666.0	599.0	564.0	289.0
Hydroelectric	**395.0**	395.0	395.0	395.0	395.0
Wind turbines	**82.0**	82.0	76.0	1.0	1.0
Diesel	**231.5**	173.0	61.0	15.0	15.0
Steam	**40.0**	47.0	51.0	-	-
Independent power producers	**300.0**	264.0	347.0	172.0	120.0
	3,388.0	3,220.0	3,122.0	2,740.0	2,428.0
Total number of employees	**2,960.0**	3,458.0	2,972.0	2,350.0	2,215.0
km of transmission lines	**6,803.0**	6,800.0	6,700.0	6,300.0	6,400.0
km of distribution lines	**39,590.0**	41,600.0	40,900.0	33,800.0	32,600.0

REGULATED ELECTRIC	Customers	Employee Count	Peak Demand (MW)	Energy Sales (GWh)	Total Assets (billions)	Rate Base (billions)	Income (millions)	Allowable ROE 2012	Allowable ROE 2011
NSPI	497,378	1906	1882	9789	$ 4.0	$ 3.7	$ 126.0	9.1-9.5%	9.1-9.6%
Bangor Hydro	118,609	302	280	1515	0.8	0.5	32.0	11.3 %	11.2 %
MPS	36,223	110	116	494	0.1	0.1	3.4	9.9 %	9.7 %
BLPC	133,687	476	157	918	0.3	0.2	19.5	10.0 %	10.0 %
GBPC	19,204	142	53	313	0.3	0.2	4.0	10 (1)%	- %

(1) GBPC is return on rate base

THREE YEAR FINANCIAL SUMMARY

For the year ended December 31 (millions of Canadian dollars)	2012	2011	2010
Consolidated Statement of Income			
Operating Revenues	**$ 2,058.6**	$ 2,064.4	$ 1,606.1
Operating expenses			
Regulated fuel for generation and purchased power	**810.5**	866.4	634.6
Regulated fuel and fixed cost adjustments	**10.0**	(8.5)	(99.0)
Non-regulated fuel for generation and purchased power	**44.5**	73.9	83.9
Non-regulated direct costs	**56.6**	60.9	62.3
Operating, maintenance and general	**462.9**	453.3	349.4
Provincial, state and municipal taxes	**49.4**	49.2	47.4
Depreciation and amortization	**278.2**	251.7	215.3
Income from operations	**346.5**	317.5	312.2
Income from equity investments and Other income (expenses), net	**53.8**	77.4	34.1
Interest expense, net	**167.1**	159.4	148.8
Income before provision for income taxes	**233.2**	235.5	197.5
Income tax expense (recovery)	**(12.4)**	(23.9)	(1.8)
Net income	**245.6**	259.4	199.3
Non-controlling interest in subsidiaries	**13.7**	11.7	5.6
Net income of Emera Incorporated	**231.9**	247.7	193.7
Preferred stock dividends	**11.1**	6.6	3.0
Net income attributable to common shareholders	**220.8**	241.1	190.7
Balance Sheets Information			
Current assets	**931.0**	993.3	840.1
Property, plant and equipment, net of accumulated depreciation	**4,491.1**	4,294.4	3,742.6
Other assets			
Deferred income taxes	**28.9**	33.1	31.1
Derivative instruments	**23.4**	39.6	36.0
Regulatory assets	**376.4**	312.2	354.9
Net investment in direct financing lease	**490.0**	492.0	491.5
Investments subject to significant influence	**536.6**	219.8	243.2
Available-for-sale investments	**141.8**	54.6	0.8
Goodwill	**193.5**	197.7	167.4
Intangibles, net of accumulated amortization	**114.2**	100.7	98.7
Due from related party	**151.7**	2.8	2.8
Other	**48.6**	183.4	69.9
Total assets	**7,527.2**	6,923.6	6,079.0
Current liabilities	**999.0**	801.7	605.9
Long-term liabilities			
Long-term debt	**3,201.1**	3,273.5	3,115.3
Deferred income taxes	**312.1**	228.6	168.5
Derivative instruments	**22.4**	38.7	28.9
Regulatory liabilities	**92.5**	107.1	65.2
Asset retirement obligations	**95.0**	99.9	141.8
Pension and post-retirement liabilities	**506.4**	530.8	400.0
Other long-term liabilities	**20.9**	19.6	22.0
Equity			
Common stock	**1,643.7**	1,385.0	1,137.8
Cumulative preferred stock	**391.6**	146.7	146.7
Contributed surplus	**2.8**	3.3	3.2
Accumulated other comprehensive loss	**(775.8)**	(671.7)	(564.2)
Retained earnings	**788.1**	735.9	653.5
Total Emera Incorporated equity	**2,050.4**	1,599.2	1,377.0
Non-controlling interest in subsidiaries	**227.4**	224.5	154.4
Total equity	**2,277.8**	1,823.7	1,531.4
Total liabilities and equity	**7,527.2**	6,923.6	6,079.0
Statements of Cash Flow Information			
Cash provided by operating activities	**397.6**	399.5	419.2
Cash used in investing activities	**(919.4)**	(660.8)	(886.0)
Cash provided by financing activities	**525.0**	331.4	454.6
Financial ratios ($ per share)			
Earnings per share	**$ 1.77**	$ 1.99	$ 1.67