# EXPLANATORY NOTE

Emera Incorporated is re-filing its Annual MD&A – English for the year ended December 31, 2011, filed on February 13, 2012, to correct: the 2011 and 2010 annual operating revenues from billions to millions on page 60 “Unbilled Revenue”.

March 2, 2012

# Management's Discussion & Analysis

As at February 10, 2012

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

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

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

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

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

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

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

# Forward Looking Information

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

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

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

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

## Structure of MD&A

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

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

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

# INTRODUCTION AND STRATEGIC OVERVIEW

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

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

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

# Non-GAAP Financial Measures

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

**NSPI**

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

**Services, Renewables and Other Investments**

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

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

# CONSOLIDATED FINANCIAL REVIEW

## Consolidated Financial Highlights

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

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

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

Highlights of the changes are summarized in the following table:

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

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

# Developments

## Emera

### Strategic Investment Agreement with Algonquin Power & Utilities Corp.

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

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

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

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

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

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

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

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

The table below summarizes the aforementioned transactions:

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

**APUC Withdrawal from First Wind Transaction**

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

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

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

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

**Emera's Investment in First Wind**

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

**Issue of Medium-Term Notes**

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

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

**Increase in Common Share Dividend**

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

**Common Share Financing**

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

**The Barbados Light & Power Company Limited**

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

**US Securities and Exchange Commission Registration**

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

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

## NSPI

**UARB Decision on 2012 Fuel Adjustment Mechanism**

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

### United States Securities and Exchange Commission Registration Status

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

### 2012 General Rate Decision

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

### NewPage Port Hawkesbury Corp.

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

### Canadian Environmental Regulations

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

### Deferral of Certain Tax Benefits Decision

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

### Light–emitting Diode Streetlight Legislation

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

### Nova Scotia Provincial Environmental Regulations

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

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

### Depreciation Settlement

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

### Digby Wind Renewable Energy Project

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

## Maine Utility Operations

### Private Placement of Senior Unsecured Notes

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

## Caribbean Utility Operations

### Sale of St. Lucia Electricity Services

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

**GBPC Credit Agreement**

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

## Appointments

**Directors**

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

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

**Executive**

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

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

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

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

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

# Significant Items

**Bear Swamp Mark-to-Market Adjustment**

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

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

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

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

**Gain on Exchange of Subscription Receipts to Shares**

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

**Gain on Business Acquisition**

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

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

# REVIEW OF 2011
# Emera Consolidated Statements of Income

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

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

Highlights of the changes are summarized in the following table:

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

# Consolidated Balance Sheets Highlights

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

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

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

# Consolidated Cash Flow Highlights

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

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

# Outstanding Share Data

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

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

# NSPI

## Overview

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

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

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

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

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

# Review of 2011

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

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

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

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

## Operating Revenues – Regulated

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

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

### Electric Revenues

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

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

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

**Q4 Electric Sales Volumes**
Gigawatt hours ("GWh")

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

**Annual Electric Sales Volumes**
GWh

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

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

**Q4 Electric Revenues**
millions of Canadian dollars

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

**Annual Electric Revenues**
millions of Canadian dollars

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

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

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

### Electric Margin

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

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

Electric margin is summarized in the following table:

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

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

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

| | **2011** | 2010 | 2009 |
|---|---|---|---|
| Dollars per MWh | $63 | $59 | $59 |

**Annual Average Electric Margin/MWh**

| | **2011** | 2010 | 2009 |
|---|---|---|---|
| Dollars per MWh | $59 | $59 | $60 |

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

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

## Regulated Fuel for Generation and Purchased Power (including affiliates)

### Capacity

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

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

**Q4 Production Volumes**
GWh

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

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

**Annual Production Volumes**
GWh

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

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

**Q4 Average Unit Fuel Costs**

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

**Annual Average Unit Fuel Costs**

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

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

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

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

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

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

Highlights of the changes are summarized in the following table:

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

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

## Regulated Fuel Adjustment

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

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

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

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

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

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

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

## Provincial Grants and Taxes

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

## Regulatory Amortization

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

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

## Other Expenses, Net

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

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

## Income Taxes

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

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

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

# MAINE UTILITY OPERATIONS

## Overview

Maine Utility Operations (“Maine Utilities”) includes Bangor Hydro Electric Company (“Bangor Hydro”), Maine Public Service Company (“MPS”) and Maine and Maritimes Corporation (“MAM”), the parent company of MPS. All amounts in the Maine Utility Operations section are reported in USD unless otherwise stated. MAM was purchased in late December 2010, thus its results are not included in the 2010 (adjusted) or 2009 (adjusted) comparative information.

Bangor Hydro and MPS are both transmission and distribution (“T&D”) electric utilities. Bangor Hydro is the second largest electric utility in Maine. Bangor Hydro has approximately $806.8 million of assets and serves approximately 118,000 customers in eastern Maine while MPS has approximately $139.6 million of assets and serves approximately 36,000 customers in northern Maine.

Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the energy delivered through both utilities’ T&D networks. Bangor Hydro owns and operates approximately 1,000 kilometers of transmission facilities and 7,200 kilometers of distribution facilities. Bangor Hydro‘s workforce is approximately 300 people. MPS owns and operates approximately 600 kilometers of transmission facilities, and 2,900 kilometers of distribution facilities. MPS’ workforce is approximately 125 people. The Maine Utilities currently have approximately $150 million of additional transmission development in progress.

Approximately 50 percent of Maine Utilities’ electric revenue represents distribution operations, 33 percent is associated with transmission operations and 17 percent relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings.

<u>Distribution Operations</u>

Maine Utilities’ distribution businesses operate under a traditional cost-of-service regulatory structure. Distribution rates are set based on an allowed ROE of 10.2 percent, on a common equity component of 50 percent.

<u>Transmission Operations</u>

*Bangor Hydro*
Bangor Hydro’s local transmission rates are set by the FERC annually on June 1, based upon a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted transmission investments and expenses. The allowed ROE for these local transmission investments is 11.14 percent. The common equity component is based upon the prior calendar year actual average balances. On June 1, 2011, Bangor Hydro’s local transmission rates decreased by approximately 10 percent (2010 – increased 37 percent).

Bangor Hydro’s bulk transmission assets are managed by the ISO-New England (“ISO”) as part of a region-wide pool of assets. The ISO manages the regions’ bulk power generation and transmission systems and administers the open access transmission tariff. Currently, Bangor Hydro, along with all other participating transmission providers, recovers the full cost of service for its transmission assets from distribution companies in New England, based on a regional formula that is updated on June 1 of each year. This formula is based on prior year regionally funded transmission investments and expenses, adjusted for current year forecasted investments and expenses. Bangor Hydro’s allowed ROE for these transmission investments ranges from 11.64 percent to 12.64 percent, and the common equity component is based upon the prior calendar year average balances. The cost recovery is recorded as transmission pool revenue in the Consolidated Statements of Income. The participating transmission providers are also required to contribute to the cost of service of such transmission assets on a ratable basis according to the proportion of the total New England load that their customers represent. These transmission pool expenses are recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income.

On June 1, 2010, Bangor Hydro's regional transmission revenue requirement increased by 22 percent, and on June 1, 2011, it increased by a further 9 percent.

*MPS*

MPS local transmission rates are set annually based on a formula through its Open Access Transmission Tariff ("OATT"). Rates derived from the previous calendar year results go into effect June 1 for wholesale customers and July 1 for retail customers. The allowed ROE for transmission operations is 10.5 percent, and is based on the actual prior calendar year common equity balances. The allowed ROE is determined by negotiation with customers in the formula change years of the OATT, which occur every three years. The last OATT formula change year was 2009. On June 1, 2011, MPS' local transmission rates increased by 3 percent for wholesale customers (2010 – increased 63 percent) and by 4 percent for retail customers (2010 – increased by 64 percent) on July 1, 2011.

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

<u>Stranded Cost Recoveries</u>

Electric utilities in Maine are entitled to recover all prudently incurred stranded costs resulting from the restructuring of the industry in 2000 that could not be mitigated or that arose as a result of rate and accounting orders issued by the MPUC. Unlike T&D operational assets, which are generally sustained with new investment, the net stranded cost regulatory asset pool diminishes over time as elements are amortized through charges to income and recovered through rates. Generally, regulatory rates to recover stranded costs are set every three years, on a levelized basis, and determined under a traditional cost-of-service approach.

*Bangor Hydro*

Bangor Hydro's net regulatory assets primarily include the costs associated with the restructuring of an above-market power purchase contract and the unamortized portion on its loss on the sale of its investment in the Seabrook nuclear facility. These net regulatory assets total approximately $65.3 million as at December 31, 2011 (2010 – $74.9 million) or 8 percent of Bangor Hydro's net asset base (2010 – 10 percent).

In May 2011, the MPUC approved an approximate 27 percent increase in Bangor Hydro's stranded cost rates for the period of June 1, 2011 to February 28, 2014. The increased stranded cost revenues are offset, for the most part by changes in regulatory amortizations, purchased power expense and resale of purchased power. The allowed ROE used in setting these new stranded cost rates is 7.4 percent, with a common equity component of 48 percent.

While the stranded cost revenue requirements differ throughout the period due to changes in annual stranded costs, the actual annual stranded cost revenues are the same during the period. To levelize the impact of the varying revenue requirements, cost or revenue deferrals are recorded as a regulatory asset or liability, and addressed in subsequent stranded cost rate proceedings, where customer rates are adjusted accordingly.

*MPS*

In December 2011, the MPUC approved MPS' stranded cost rates for the three-year period January 1, 2012 through December 31, 2014. This revised three-year agreement, which amortizes essentially all of MPS' remaining stranded costs, has an ROE of 7.2 percent and a common equity component of 50 percent. Any residual stranded costs remaining after December 31, 2014 will be recovered in future rate proceedings.

## Review of 2011

| **Maine Utilities' Net Income**<br>millions of US dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2011** | 2010 (adjusted) | **2011** | 2010 (adjusted) | 2009 (adjusted) |
| Operating revenues – regulated | **$50.6** | $42.8 | **$204.1** | $167.2 | $151.5 |
| Operating revenues – non-regulated | **0.1** | - | **0.5** | - | - |
| Total operating revenues | **50.7** | 42.8 | **204.6** | 167.2 | 151.5 |
| Regulated fuel for generation and purchased power | **9.2** | 7.5 | **27.9** | 29.2 | 27.7 |
| Transmission pool expense (1) | **4.3** | 4.9 | **17.9** | 18.3 | 15.5 |
| Operating, maintenance and general | **10.6** | 10.2 | **45.3** | 36.3 | 29.6 |
| Provincial, state and municipal taxes | **2.2** | 1.6 | **9.0** | 6.8 | 6.3 |
| Depreciation and amortization | **8.4** | 5.1 | **36.9** | 20.9 | 23.5 |
| Total operating expenses | **34.7** | 29.3 | **137.0** | 111.5 | 102.6 |
| Income from operations | **16.0** | 13.5 | **67.6** | 55.7 | 48.9 |
| Other income | **1.6** | 1.1 | **4.3** | 4.1 | 2.3 |
| Interest expense, net | **2.8** | 2.7 | **11.8** | 10.7 | 12.2 |
| Income before provision for income taxes | **14.8** | 11.9 | **60.1** | 49.1 | 39.0 |
| Income tax expense | **5.2** | 4.3 | **22.7** | 18.2 | 13.9 |
| Contribution to consolidated net income – USD | **$9.6** | $7.6 | **$37.4** | $30.9 | $25.1 |
| Contribution to consolidated net income – CAD | **$9.8** | $7.8 | **$37.0** | $31.9 | $27.5 |
| Contribution to consolidated earnings per common share – CAD | **$0.08** | $0.07 | **$0.31** | $0.28 | $0.24 |
| Net income weighted average foreign exchange rate – CAD/USD | **$1.02** | $1.03 | **$0.99** | $1.03 | $1.10 |

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

Maine Utilities' contribution to consolidated net income increased by $2.0 million to $9.6 million in Q4 2011 compared to $7.6 million in Q4 2010 (adjusted). Maine Utilities' contribution to consolidated net income increased by $6.5 million to $37.4 million for the year ended December 31, 2011 compared to $30.9 million in 2010 (adjusted) and $25.1 million in 2009 (adjusted).

Highlights of the net income changes are summarized in the following table:

| For the<br>millions of US dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2009 (adjusted)** | | **$25.1** |
| Increased electric revenue due primarily to transmission rate increases in 2009 and 2010 | | 6.1 |
| Increased transmission pool revenue due to recovery of regionally funded transmission investments | | 10.2 |
| Increased OM&G expenses primarily due to increased labour and benefit costs and lower capitalized construction overheads | | (6.7) |
| Increased transmission pool expenses due to increased charges for Bangor Hydro's share of regionally funded transmission investments and expenses as well as favourable temperatures during high peak electric loads in New England in 2010 | | (2.8) |
| Increased income tax expense primarily due to increased income before provision for income taxes | | (4.3) |
| Other | | 3.3 |
| **Contribution to consolidated net income – 2010 (adjusted)** | **$7.6** | **$30.9** |
| Decreased electric revenue during the quarter in Bangor Hydro due to lower sales volumes resulting from warmer temperatures, a transmission rate decrease in June 2011 and lower transmission wheeling revenue from a wind generator | (2.0) | (0.9) |
| Increased transmission pool revenue year-over-year primarily due to recovery on larger regionally funded transmission investments, partially offset by less favourable weather in 2011 | (0.4) | 2.2 |
| Decreased OM&G expenses in Bangor Hydro primarily due to an increase in capitalized construction overheads | 2.9 | 3.9 |
| Increased Bangor Hydro income tax expense primarily due to increased income before provision for income taxes | (0.5) | (2.7) |
| Impact of the acquisition of MAM net of income taxes | 1.1 | 2.7 |
| Other | 0.9 | 1.3 |
| **Contribution to consolidated net income – 2011** | **$9.6** | **$37.4** |

Maine Utilities' USD and CAD contribution to consolidated net income increased in Q4 2011 and for the year ended December 31, 2011. The impact of a stronger Canadian dollar, year over year, reduced CAD earnings by $0.1 million in Q4 2011 and $1.5 million for the year ended December 31, 2011.

For the three months ended December 31, 2011, MPS contributed approximately $9.2 million to Maine Utilities' Operating revenues – regulated and $1.1 million to consolidated net income. For the year ended December 31, 2011, MPS contributed approximately $34.9 million to Maine Utilities' Operating revenues – regulated and $2.7 million to consolidated net income. MPS was purchased in late December 2010, and accordingly did not have an impact on 2010 or 2009 operating revenues – regulated nor consolidated net income.

## Operating Revenues – Regulated

**Q4 Operating Revenues – Regulated**
millions of US dollars

| | **2011** | * 2010 (adjusted) | * 2009 (adjusted) |
|---|---|---|---|
| Residential | **$17.2** | $13.6 | $12.6 |
| Commercial | **14.3** | 10.3 | 9.1 |
| Industrial | **2.6** | 2.9 | 2.4 |
| Other | **3.0** | 2.2 | 1.9 |
| Total electric revenues | **$37.1** | $29.0 | $26.0 |
| Resale of purchased power | **4.7** | 4.6 | 4.9 |
| Transmission pool | **8.8** | 9.2 | 7.0 |
| Operating revenues – regulated | **$50.6** | $42.8 | $37.9 |

**Annual Operating Revenues – Regulated**
millions of US dollars

| | **2011** | *2010 (adjusted) | *2009 (adjusted) |
|---|---|---|---|
| Residential | **$68.1** | $50.6 | $48.3 |
| Commercial | **56.2** | 39.4 | 35.9 |
| Industrial | **11.2** | 11.5 | 10.2 |
| Other | **10.3** | 9.4 | 10.4 |
| Total electric revenues | **$145.8** | $110.9 | $104.8 |
| Resale of purchased power | **18.1** | 18.3 | 18.9 |
| Transmission pool | **40.2** | 38.0 | 27.8 |
| Operating revenues – regulated | **$204.1** | $167.2 | $151.5 |

Electric sales volume is primarily driven by general economic conditions, population and weather. Electric sales pricing in Maine is regulated, and therefore changes in accordance with regulatory decisions.

| For the<br>millions of US dollars | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Operating revenues – regulated 2009** | | **$151.5** |
| Increased electric revenues due to increased transmission rates discussed below, increased load offset by a reduction in stranded cost rates | | 6.1 |
| Increased transmission pool revenues due to recovery of higher regionally-funded transmission investments and more favourable temperatures | | 10.2 |
| Other | | (0.6) |
| **Operating revenues – regulated 2010** | **$42.8** | **$167.2** |
| Increased electric revenues due to acquisition of MAM, the effect of transmission rate changes discussed below, partially offset by less favourable temperatures in 2011 | 8.1 | 34.9 |
| Increased transmission pool revenues year-over-year due to recovery of higher regionally-funded transmission investments partially offset by less favourable temperatures in 2011 | (0.4) | 2.2 |
| Other | 0.1 | (0.2) |
| **Operating revenues – regulated 2011** | **$50.6** | **$204.1** |

## Electric Revenue

**Q4 Electric Sales Volumes**

| GWh | **2011** | * 2010 | * 2009 |
|---|---|---|---|
| Residential | **196.2** | 155.0 | 154.2 |
| Commercial | **207.4** | 146.7 | 144.8 |
| Industrial | **91.1** | 84.4 | 78.2 |
| Other | **2.8** | 2.9 | 2.9 |
| Total | **497.5** | 389.0 | 380.1 |

**Annual Electric Sales Volumes**

| GWh | **2011** | * 2010 | * 2009 |
|---|---|---|---|
| Residential | **778.5** | 591.0 | 591.5 |
| Commercial | **846.4** | 594.1 | 588.0 |
| Industrial | **380.5** | 363.0 | 342.0 |
| Other | **11.4** | 11.6 | 11.6 |
| Total | **2,016.8** | 1,559.7 | 1,533.1 |

*MAM is not included in 2010 and 2009 operating statistics.

**Q4 Average Electric Revenue/MWh**

| | **2011** | *2010 (adjusted) | *2009 (adjusted) |
|---|---|---|---|
| Dollars per MWh | **$75** | $75 | $68 |

**Annual Average Electric Revenue/MWh**

| | **2011** | *2010 (adjusted) | *2009 (adjusted) |
|---|---|---|---|
| Dollars per MWh | **$72** | $71 | $68 |

*MAM is not included in 2010 and 2009 operating statistics.

There was no change in annual average electric revenue per MWh in 2011 compared to 2010 (adjusted). Decreased transmission rates were offset by increased stranded cost rates.

The change in average electric revenue per MWh in 2010 (adjusted) compared to 2009 (adjusted) reflects increases in transmission rates on June 1, 2010, November 1, 2009 and June 1, 2009, partially offset by the impact of a stranded cost rate decrease on June 1, 2009.

## Regulated Fuel for Generation and Purchased Power

Bangor Hydro has several above-market purchase power contracts pre-dating the Maine market restructuring, as well as an additional power purchase contract entered into in Q3 2011 with a wind generator. Power purchased under the older arrangements is resold to a third party at market rates as determined through a bid process administered and approved by the MPUC, while the purchased power from the wind generator is sold directly into the New England market. The difference between the cost of the power purchased under these arrangements and the revenue collected is recovered through stranded cost rates under a full reconciliation rate mechanism.

MPS has an expired power purchase contract that is currently being recovered in stranded cost rates and the related deferred asset is being amortized accordingly.

## Income Taxes

Maine Utilities’ are subject to corporate income tax at the statutory rate of 40.8 percent (combined US federal and state income tax rate).

# CARIBBEAN UTILITY OPERATIONS

## Overview

Caribbean Utility Operations includes Emera's:

- 80.1 percent investment in Light & Power Holdings Ltd. ("LPH") and its wholly-owned subsidiary Barbados Light & Power Company Ltd. ("BLPC"). BLPC is a vertically-integrated utility and the sole provider of electricity on the island of Barbados which serves approximately 123,000 customers and is regulated by the Fair Trading Commission, Barbados. The government of Barbados has granted BLPC a franchise to produce, transmit and distribute electricity on the island until 2028. BLPC is regulated under a cost-of-service model with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. BLPC's approved regulated return on assets for 2011 is 10 percent. BLPC's first rate adjustment since 1983 was approved in January 2010 and was effective March 1, 2010. A fuel pass-through mechanism ensures fuel costs are recovered. A controlling interest in LPH was acquired in January 2011, and accordingly its results are not consolidated in the 2010 and 2009 comparative information; these results contain only equity income.

- 50 percent direct and 30.4 percent indirect interest in Grand Bahama Power Company Ltd. ("GBPC"), a vertically-integrated utility and the sole provider of electricity on Grand Bahama Island. GBPC serves 19,000 customers and is regulated by GBPA, which has granted it a licensed, regulated and exclusive franchise to produce, transmit and distribute electricity on the island until 2054. There is a fuel pass-through mechanism and flexible tariff adjustment policy to ensure costs are recovered and a reasonable return earned. A controlling interest in GBPC was acquired in December 2010, and accordingly its results are not consolidated in the 2010 and 2009 comparative information; these results contain only equity income.

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

# Review of 2011

**Caribbean Utility Operations' Net Income**

| millions of Canadian dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2011** | 2010 (adjusted) | **2011** | 2010 (adjusted) | 2009 (adjusted) |
| Operating revenues – regulated | **$108.0** | - | **$406.3** | - | - |
| Regulated fuel for generation and purchased power | **73.4** | - | **273.7** | - | - |
| Operating, maintenance and general (1) | **23.5** | $6.9 | **87.3** | $6.9 | - |
| Property taxes | **0.3** | - | **1.4** | - | - |
| Depreciation and amortization | **5.4** | - | **22.6** | - | - |
| Total operating expenses | **102.6** | 6.9 | **385.0** | 6.9 | - |
| Income from operations | **5.4** | (6.9) | **21.3** | (6.9) | - |
| Income from equity investments | **0.7** | (0.7) | **2.8** | 4.7 | $3.6 |
| Other income (expenses), net | **0.3** | (2.6) | **35.7** | 19.7 | - |
| Interest expense, net | **2.2** | - | **8.6** | - | - |
| Income before provision for income taxes | **4.2** | (10.2) | **51.2** | 17.5 | 3.6 |
| Income tax expense | **0.5** | - | **0.7** | - | - |
| Net income | **3.7** | (10.2) | **50.5** | 17.5 | 3.6 |
| Non-controlling interest in subsidiaries | **0.6** | (2.5) | **3.7** | (2.3) | 0.7 |
| Contribution to consolidated net income | **$3.1** | $(7.7) | **$46.8** | $19.8 | $2.9 |
| Contribution to consolidated earnings per common share | **$0.03** | $(0.06) | **$0.39** | $0.17 | $0.03 |

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

Caribbean Utility Operations' contribution to consolidated net income increased by $10.8 million to $3.1 million in Q4 2011 compared to a loss of $7.7 million in Q4 2010 (adjusted). For the year ended December 31, 2011, contribution to consolidated net income increased by $27.0 million to $46.8 million in 2011 compared to $19.8 million in 2010 (adjusted) and $2.9 million in 2009 (adjusted). Highlights of the net income changes are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2009 (adjusted)** | | **$2.9** |
| Gain on initial investment in LPH | | 22.5 |
| GBPC acquisition-related costs | | (6.1) |
| Increased income from equity investment in LPH | | 5.4 |
| Decreased income from equity investment in GBPC | | (1.0) |
| Loss on acquisition of GBPC | | (2.4) |
| Other | | (1.5) |
| **Contribution to consolidated net income – 2010 (adjusted)** | **$(7.7)** | **$19.8** |
| Gain on initial investment in LPH recorded in 2010 | - | (22.5) |
| Gain on acquisition of controlling interest in LPH in 2011 | - | 28.2 |
| GBPC acquisition-related costs recorded in 2010 | 6.1 | 7.3 |
| Increased income from increased investments in LPH and GBPC | 1.1 | 9.3 |
| Increased income due to regulatory deferral in GBPC | - | 4.4 |
| Other | 3.6 | 0.3 |
| **Contribution to consolidated net income – 2011** | **$3.1** | **$46.8** |

## Operating Revenues – Regulated

**Q4 Operating Revenues – Regulated**
millions of Canadian dollars

| | 2011 |
|---|---|
| Residential electric revenues | **$11.6** |
| Commercial electric revenues | **20.0** |
| Industrial electric revenues | **3.9** |
| Other electric revenues | **0.9** |
| Total electric revenues | **$36.4** |
| Other – service installation revenue and fuel surcharge | **71.6** |
| Operating revenues - regulated | **$108.0** |

**Annual Operating Revenues – Regulated**
millions of Canadian dollars

| | 2011 |
|---|---|
| Residential electric revenues | **$45.3** |
| Commercial electric revenues | **84.5** |
| Industrial electric revenues | **14.3** |
| Other electric revenues | **3.6** |
| Total electric revenue | **$147.7** |
| Other – service installation revenue and fuel surcharge | **258.6** |
| Operating revenues – regulated | **$406.3** |

## Electric Revenue

Electric sales volume is primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal, with Q2 and Q3 the strongest periods, reflecting warmer weather.

**Q4 Electric Sales Volumes**
GWh

| | 2011 |
|---|---|
| Residential | **97.3** |
| Commercial | **179.9** |
| Industrial | **23.6** |
| Other | **5.7** |
| Total | **306.5** |

**Annual Electric Sales Volumes**
GWh

| | 2011 |
|---|---|
| Residential | **384.8** |
| Commercial | **701.1** |
| Industrial | **91.9** |
| Other | **21.8** |
| Total | **1,199.6** |

**Q4 Average Electric Revenue/MWh**

| | 2011 |
|---|---|
| Dollars per MWh | **$119** |

**Annual Average Electric Revenue/MWh**

| | 2011 |
|---|---|
| Dollars per MWh | **$123** |

## Regulated Fuel for Generation and Purchased Power

**Q4 Production Volumes**
GWh

| | 2011 |
|---|---|
| Oil | **339.2** |

**Annual Production Volumes**
GWh

| | 2011 |
|---|---|
| Oil | **1,316.7** |

**Q4 Average Unit Fuel Costs**

| | 2011 |
|---|---|
| Dollars per MWh | **$216** |

**Annual Average Unit Fuel Costs**

| | 2011 |
|---|---|
| Dollars per MWh | **$208** |

## Fuel Recovery Mechanisms

### BLPC

All BLPC fuel costs are passed to customers through the fuel clause adjustment (“fuel surcharge”). Fair Trading Commission, Barbados has approved the calculation of the fuel surcharge, which is adjusted on a monthly basis. BLPC has the ability to carryover an under-recovery to later months to smooth the fuel surcharge for customers.

### GBPC

The base tariff for GBPC includes a component to recover the cost of $20 USD per barrel of oil consumed by GBPC for generation of electricity. The amount by which actual fuel costs exceed $20 USD dollars per barrel is recovered or rebated through the fuel surcharge, which is adjusted on a monthly basis. The methodology for calculating the amount of the fuel surcharge has been approved by GBPA.

## Income from Equity Investments

In 2011, income from equity investments included Emera's 19.1 percent investment in Lucelec only. Emera acquired controlling interests in GBPC in December 2010 and LPH in January 2011, and accordingly those investments are consolidated in 2011.

In 2010, income from equity investments included Emera's 19.1 percent interest in Lucelec, its 25 percent investment in GBPC prior to acquiring the controlling interest in December 2010, and the 38.4 percent investment in LPH, which was acquired that year. In 2009, income for equity investment included the Lucelec and GBPC investments.

## Regulatory Deferrals

On July 14, 2011, GBPA approved the recovery of a $4.7 million asset impairment charge recorded in 2010. As a result, the charge was reversed through earnings in Q3 2011, and recorded as a regulatory asset, which will be amortized into income over a 25 year period commencing upon completion of the new 52 MW diesel generation unit scheduled to be on line mid-2012.

On April 12, 2011, GBPA approved, as part of the fuel surcharge, the recovery of the net costs of leasing the temporary generation required to meet peak demand for electricity until the commission of a new 52-MW power plant. The amount by which the actual cost of the temporary generation exceeds what has been recovered through the fuel surcharge has been recorded as a regulatory asset which will be amortized into income.

## Income Taxes

The Caribbean Utility Operations are subject to corporate income tax at the following statutory rates:

- LPH is subject to corporate income tax at the statutory rate of 25 percent;
- BLPC is subject to corporate income tax at the statutory rate of 15 percent;
- GBPC is not subject to corporate income tax; and
- Lucelec is subject to corporate income tax at the statutory rate of 30 percent. Equity income is recorded net of tax.

# PIPELINES

## Overview

Pipelines comprises Emera's wholly-owned Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline") and the Company's 12.9 percent interest in the Maritimes & Northeast Pipeline ("M&NP").

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Canaport™ re-gasified liquefied natural gas ("LNG") import terminal near Saint John, New Brunswick, to markets in the northeastern United States. The pipeline, which went into service in July 2009, transports re-gasified liquefied natural gas for Repsol Energy Canada under a 25 year firm service agreement. The NEB, which regulates Brunswick Pipeline, has classified it as a Group II pipeline. Brunswick Pipeline is accounted for as a direct financing lease.

M&NP is a $2 billion, 1,400-kilometer pipeline which transports natural gas from offshore Nova Scotia to markets in Maritime Canada and the northeastern United States. The investment in M&NP is equity accounted.

## Review of 2011

| **Pipelines' Net Income**<br>millions of Canadian dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2011** | 2010 (adjusted) | **2011** | 2010 (adjusted) | 2009 (adjusted) |
| Brunswick Pipeline | | | | | |
| Operating revenues – regulated | **$12.7** | $12.0 | **$49.7** | $48.9 | $22.5 |
| Other income (expense), net | **(0.2)** | 0.8 | **0.2** | 1.4 | 18.9 |
| Interest expense, net | **7.6** | 7.7 | **30.2** | 30.6 | 21.5 |
| Brunswick Pipeline net income | **4.9** | 5.1 | **19.7** | 19.7 | 19.9 |
| Income from equity investment | **2.0** | 2.9 | **8.2** | 9.2 | 10.2 |
| Contribution to consolidated net income | **$6.9** | $8.0 | **$27.9** | $28.9 | $30.1 |
| Contribution to consolidated earnings per common share | **$0.06** | $0.07 | **$0.23** | $0.25 | $0.27 |

Pipelines' contribution to consolidated net income decreased by $1.1 million to $6.9 million in Q4 2011 compared to $8.0 million in Q4 2010 (adjusted). For the year ended December 31, 2011, Pipelines' contribution to consolidated net income decreased $1.0 million to $27.9 million compared to $28.9 million in 2010 (adjusted) and $30.1 million in 2009 (adjusted). Highlights of the income changes are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2009 (adjusted)** | | **$30.1** |
| Brunswick Pipeline – Decreased net income primarily due to unfavorable change in the mark-to-market of currency hedges, partially offset by a full year of operations in 2010 | | (0.2) |
| Decreased income from equity investment primarily due to increased MN&P financing charges on the US portion of the pipeline as a result of debt recapitalization, and the recognition of a settlement in the first half of 2009 combined with a stronger CAD in 2010 | | (1.0) |
| **Contribution to consolidated net income – 2010 (adjusted)** | **$8.0** | **$28.9** |
| Brunswick Pipeline – Decreased net income during the quarter primarily due to the unfavorable change in the mark-to-market of currency hedges | (0.2) | - |
| Decreased income from equity investment due to lower toll rates in M&NP | (0.9) | (1.0) |
| **Contribution to consolidated net income – 2011** | **$6.9** | **$27.9** |

## Brunswick Pipeline

The Company records the net investment in a lease under the direct finance method, which consists of the sum of the minimum lease payments and residual value net of estimated executory costs and unearned income. This accounting method has the effect of recognizing higher revenues in the early years of the contract than would have been recorded if the toll revenues were recorded as received.

## Income Taxes

Brunswick Pipeline is subject to corporate income tax at the statutory rate of 27.0 percent (combined Canadian federal and provincial income tax rate). M&NP's equity income is recorded net of tax.

# SERVICES, RENEWABLES AND OTHER INVESTMENTS

## Overview

Services, Renewables and Other Investments ("SRO") includes Emera Energy ("Emera Energy"); Emera Utility Services Inc. ("EUS"); and Emera Newfoundland & Labrador Holdings Inc. ("ENL"), as well as other investments.

- Emera Energy includes:
  - Emera Energy Services, a physical energy business which purchases and sells natural gas and electricity and provides related energy asset management services.
  - Bayside Power, a 260-MW gas-fired merchant electricity generating facility in Saint John, New Brunswick.
  - Emera's 50 percent joint venture ownership of Bear Swamp, a 600-MW pumped storage hydro-electric facility in northern Massachusetts. This investment is equity accounted.

- EUS is a utility services contractor.

- ENL is a wholly-owned subsidiary of Emera focused on transmission investments related to a proposed 824-MW hydro-electric generating facility at Muskrat Falls in Labrador. These investments include an estimated $1.2 billion transmission project between Newfoundland and Nova Scotia, incorporating a 180-kilometre subsea cable ("Maritime Link Project"). In addition, together with Nalcor Energy, Newfoundland and Labrador's provincial energy crown corporation leading the project in that province, Emera is investing in the development of a $2.1 billion electricity transmission project in Newfoundland and Labrador ("Labrador-Island Transmission Link Project"). These projects are scheduled to be in service in 2017. Development costs incurred to date have been capitalized.

- Other investments include a 6.26 percent investment in Algonquin Power & Utilities Corporation ("APUC"), a 49.999 percent investment in California Pacific Utilities Ventures ("CPUV") and a 37.7 percent investment in Atlantic Hydrogen Inc. ("AHI"). These investments are equity accounted.

## Review of 2011

Emera Energy and EUS are reported on an income before interest expense, net and income tax expense (recovery) ("EBIT") basis.

| **Services, Renewables and Other Investments Net Income**<br>millions of Canadian dollars (except per share amounts) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2011** | 2010 (adjusted) | **2011** | 2010 (adjusted) | 2009 (adjusted) |
| Emera Energy | **$2.4** | $(0.3) | **$7.6** | $3.6 | $10.9 |
| EUS | **2.1** | 3.0 | **4.4** | 7.0 | 1.8 |
| Income (loss) from equity investments | **0.7** | 0.2 | **2.9** | (0.3) | - |
| Other income, net | **0.5** | - | **14.6** | - | - |
| Interest expense, net | **-** | 0.2 | **0.9** | 1.2 | 1.7 |
| Income tax expense (recovery) | **(0.3)** | 0.9 | **1.6** | 0.5 | (3.7) |
| Contribution to consolidated net income | **$6.0** | $1.8 | **$27.0** | $8.6 | $14.7 |
| Bear Swamp after-tax mark-to-market adjustment | **$(0.7)** | $(2.6) | **$(0.8)** | $(8.6) | $0.7 |
| Contribution to consolidated net income, absent the Bear Swamp after-tax mark-to-market adjustment | **$6.7** | $4.4 | **$27.8** | $17.2 | $14.0 |
| Contribution to consolidated earnings per common share | **$0.05** | $0.02 | **$0.22** | $0.08 | $0.13 |
| Contribution to consolidated earnings per common share, absent the Bear Swamp after-tax mark-to-market adjustment | **$0.06** | $0.04 | **$0.23** | $0.15 | $0.12 |

SRO's contribution to consolidated net income increased by $4.2 million to $6.0 million in Q4 2011 compared to net income of $1.8 million in Q4 2010 (adjusted). For the year ended December 31, 2011, contribution to consolidated net income increased $18.4 million to $27.0 million compared to $8.6 million in 2010 (adjusted) and $14.7 million in 2009 (adjusted). Highlights of the income changes are summarized in the following table:

| For the<br>millions of Canadian dollars | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2009 (adjusted)** | | **$14.7** |
| Emera Energy – Decreased due primarily to an unfavourable change in the fair value of the net derivatives in Bear Swamp, lower equity income and the stronger CAD, partially offset by improved Emera Energy results | | (7.3) |
| EUS – Increased primarily due to the successful completion of large construction projects and the expansion of the communications business | | 5.2 |
| Income tax expense – Increased due to increased income | | (4.2) |
| Other | | 0.2 |
| **Contribution to consolidated net income – 2010 (adjusted)** | **$1.8** | **$8.6** |
| Emera Energy – Increased during the quarter and year-over-year due to a positive change in the fair value of the net derivatives in Bear Swamp; increased year-over-year also due to stronger energy marketing results, partially offset by the reversal of 2010 mark-to-market gains | 2.7 | 4.0 |
| EUS – Decreased due to reduced construction activity | (0.9) | (2.6) |
| Income from equity investments – Increased investments in APUC and CPUV | 0.5 | 3.2 |
| Other income, net – Increased year-over-year primarily due to an after-tax gain of $12.8 million on APUC subscription receipts | 0.5 | 14.6 |
| Income tax expense – Increased year-over-year primarily due to the taxable gain on APUC subscription receipts | 1.2 | (1.1) |
| Other | 0.2 | 0.3 |
| **Contribution to consolidated net income – 2011** | **$6.0** | **$27.0** |

## Emera Energy

### Bear Swamp Mark-to-Market Adjustment

Bear Swamp has an agreement to supply energy and capacity to the Long Island Power Authority ("LIPA") through to 2021. Bear Swamp has contracted with its joint venture partner to provide the power necessary to produce the requirements of the LIPA contract. One of the contracts between Bear Swamp and Emera is marked-to-market through earnings, as it does not meet the stringent accounting requirements for hedge accounting.

As at December 31, 2011 the fair value of the contract was a net liability of $9.6 million (December 31, 2010 (adjusted) – $8.2 million net liability). The fair value of this derivative is subject to market volatility of power prices and will reverse over the life of the agreement as it is realized.

## Other Income, Net

Other income, net includes Emera's 6.26 percent investment in APUC, 49.999 percent investment in CPUV and a 37.7 percent investment in AHI.

## Income Taxes

Emera Energy is subject to corporate income tax at the statutory rate of 41.0 percent (combined US federal and state income tax rate) on its US sourced income and 30.9 percent (combined Canadian federal and provincial) on its Canada sourced income. Bear Swamp's equity income is recorded net of tax.

EUS is subject to corporate income tax at the statutory rate of 30.9 percent (combined Canadian federal and provincial).

# CORPORATE

## Overview

Corporate includes certain corporate-wide functions including executive management, strategic planning, treasury services, financial reporting, tax planning, business development and corporate governance. Corporate also includes interest expense and income taxes associated with corporate activities.

## Review of 2011

| **Corporate**<br>millions of Canadian dollars | Three months ended<br>December 31 | | | Year ended<br>December 31 | |
|---|---|---|---|---|---|
| | **2011** | 2010<br>(adjusted) | **2011** | 2010<br>(adjusted) | 2009<br>(adjusted) |
| Revenue | **$7.6** | $7.7 | **$30.2** | $30.6 | $30.0 |
| Corporate costs | **4.4** | 9.2 | **27.3** | 27.3 | 21.4 |
| Interest expense | **8.5** | 7.7 | **33.9** | 32.0 | 22.8 |
| Income tax recovery | **(4.1)** | (3.5) | **(16.5)** | (14.0) | (14.5) |
| | **(1.2)** | (5.7) | **(14.5)** | (14.7) | 0.3 |
| Preferred stock dividends | **-** | - | **6.6** | 3.0 | - |
| Contribution to consolidated net income | **$(1.2)** | $(5.7) | **$(21.1)** | $(17.7) | $0.3 |

**Revenue**

Revenue consists of intercompany interest and preferred dividends from Brunswick Pipeline.

**Corporate Costs**

Corporate costs decreased by $4.8 million to $4.4 million in Q4 2011 compared to $9.2 million in Q4 2010 (adjusted) due primarily to decreased deferred compensation and business acquisition costs as well as foreign exchange gains resulting from a stronger CAD. Corporate costs increased $5.9 million to $27.3 million in 2010 (adjusted) compared to $21.4 million in 2009 due to acquisition-related costs.

**Interest Expense**

Interest expense increased $0.8 million to $8.5 million in Q4 2011 compared to $7.7 million in Q4 2010 (adjusted). Interest expense increased $1.9 million to $33.9 million for the year ended December 31, 2011 compared to $32.0 million in 2010 (adjusted) and $22.8 million in 2009 due to an increase in borrowings primarily to fund business acquisitions.

**Income Tax Recovery**

Income tax recovery increased by $0.6 million to $4.1 million in Q4 2011 compared to $3.5 million in Q4 2010 (adjusted) and increased $2.5 million to $16.5 million for the year ended December 31, 2011 compared to $14.0 million in 2010 (adjusted) primarily due to increased interest expense.

**Preferred Stock Dividends**

Preferred stock dividends increased $3.6 million to $6.6 million for the year ended December 31, 2011; compared to $3.0 million in 2010 (adjusted); and increased for the year ended December 31, 2010, by $3.0 million from nil in 2009 (adjusted), due to the issuance of preferred shares in June 2010.

# OUTLOOK

Emera will continue to pursue investment opportunities related to the transformation of the energy industry to produce lower emissions. Emera has embarked on a significant capital plan to increase the Company's generation from renewable sources, to improve the transmission connections within its service territories, and to expand access to natural gas as Emera transitions to a cleaner, greener company.

Although markets in Maine and Nova Scotia are otherwise mature, the transformation of energy supply to lower emission sources has created the opportunity for organic growth within NSPI and Emera's Maine Utility Operations. The utilities expect average income growth to be 3 percent to 5 percent annually over the next five years as new investments are made in renewable generation and transmission.

## NSPI

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

## Maine Utility Operations

USD income from Maine Utility Operations is expected to be slightly higher in 2012 compared to 2011 due to the recovery of investments in new transmission assets. In 2012, Maine Utilities expects to invest approximately $116 million USD, including approximately $78 million USD for major transmission projects.

## Caribbean Utility Operations

Income from Caribbean Utility Operations is expected to be higher in 2012 compared to 2011 primarily as a result of increased capital investments in LPH and GBPC. Caribbean Utility Operations plans to invest approximately $63 million in capital programs in 2012.

## Pipelines

Income from Pipelines is expected to decline marginally in 2012 as compared to 2011 as a result of capital lease accounting treatment which yields declining earnings over the life of the asset.

## Services, Renewables and Other Investments

Income from Services, Renewables and Other Investments is expected to be consistent with 2011. ENL plans to invest approximately $100 million on the Maritime Link Project and Labrador-Island Transmission Link Project in 2012.

## Corporate

Income from Corporate is expected to be lower in 2012 compared to 2011 due to higher interest costs due to business growth.

# LIQUIDITY AND CAPITAL RESOURCES

The Company generates cash primarily through the generation, transmission and distribution of electricity through its regulated electric utilities. The utilities' customer bases are diversified by both sales volumes and revenues among customer classes. Circumstances that could affect the Company's ability to generate cash include general economic downturns in Emera's markets, the loss of one or more large customers, regulatory decisions affecting customer rates and changes in environmental legislation. Emera's subsidiaries are capable of paying dividends to Emera provided they do not breach their debt covenants after giving effect to the dividend payment.

In addition to internally generated funds, Emera and its subsidiaries have, in aggregate access to $1.3 billion committed syndicated revolving bank lines of credit as discussed in the table below. In August 2011, Emera increased its committed syndicated bank line from $600 million to $700 million, and NSPI reduced its committed syndicated revolving bank line from $600 million to $500 million. The maturity of both facilities was extended from June 2013 to June 2015. NSPI has an active commercial paper program for up to $400 million, of which outstanding amounts are 100 percent backed by NSPI's bank line referred to above, which results in an equal amount of credit being considered drawn and unavailable.

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

| millions of dollars | Maturity | Revolving Credit Facilities | Utilized | Undrawn and Available |
|---|---|---|---|---|
| Emera – Operating and acquisition credit facility | June 2015 – Revolver | $700 | $263 | 437 |
| NSPI – Operating credit facility | June 2015 – Revolver | 500 | 318 | 182 |
| Bangor Hydro – in USD – Operating credit facility | September 2013 – Revolver | 80 | 66 | 14 |
| Other – in USD – Operating credit facilities | 2012 | 21 | 8 | 13 |

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements.

## Debt Management

### Emera

In February 2011, Emera filed an amended and restated short form base shelf prospectus. This amendment increased the aggregate principal amount of debt securities and preferred shares that may be offered from time to time under the short form base shelf prospectus from $500 million to $650 million. As at December 31, 2011, $150 million in preferred shares and $250 million of medium-term notes have been issued under the short form base shelf prospectus and shelf prospectus supplements.

The weighted average coupon rate of Emera's outstanding medium-term notes as at December 31, 2011 was 3.93 percent (2010 – 4.45 percent). All of the outstanding debt matures within the next ten years. The quoted yield for the same or similar issues of the same remaining maturities was 2.88 percent as at December 31, 2011 (2010 – 3.73 percent).

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

| | DBRS | S&P |
|---|---|---|
| Long-term corporate | BBB (high) | BBB+ |
| Preferred stock | Pfd-3 (high) | P-2 (Low) |

## NSPI

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

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

The weighted average coupon rate on NSPI's outstanding medium-term and debenture notes as at December 31, 2011 and 2010 was 6.74 percent. Approximately 27 percent of the debt matures over the next ten years, 70 percent matures between 2021 and 2040 and 3 percent, matures in 2097. The quoted yield for the same or similar issues of the same remaining maturities was 3.51 percent as at December 31, 2011 (2010 – 4.50 percent).

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

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

## Maine Utility Operations

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

On April 27, 2011, MPS renewed its existing $10 million USD revolving credit facility, with a new expiration date of December 31, 2012.

On June 24, 2010, Bangor Hydro entered into a 39 month revolving credit facility for $80 million USD.

The weighted-average coupon rate on Bangor Hydro's outstanding long-term debt as at December 31, 2011 was 7.01 percent (2010 – 6.96 percent). Approximately 87 percent of the debt matures over the next 10 years; the remaining matures in 2022. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 2.54 percent as at December 31, 2011 (2010 – 3.81 percent).

The weighted-average coupon rate on MPS' outstanding long-term debt as at December 31, 2011 and 2010 was 4.46 percent. All of the debt matures over the next 10 years. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 3.58 percent as at December 31, 2011 (2010 – 4.85 percent).

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

### Caribbean Utility Operations

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

In October 2011, GBPC entered into a 12 month revolving credit facility for $11 million Bahamian dollars.

The weighted-average coupon rate on BLPC's' outstanding long-term debt as at December 31, 2011, was 6.30 percent. Approximately 77 percent of the debt matures over the next 10 years; the remaining issue matures in 2025. The market weighted average interest rate is based on the last rate of debt issuances of 6.85 percent.

The weighted-average coupon rate on GBPC's outstanding long-term debt as at December 31, 2011, was 6.64 percent (2010 – 6.61 percent). Approximately 66 percent of the debt matures over the next 10 years; the remaining issue matures in 2023. The market weighted average interest rate is 7.00 percent as at December 31, 2011 (2010 – 5.86 percent), based on the last rate of debt issuances.

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

## Contractual Obligations

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

| millions of Canadian dollars | **Total** | **2012** | **2013** | **2014** | **2015** | **2016** | **Thereafter** |
|---|---|---|---|---|---|---|---|
| Long-term debt (1) | $3,307.0 | $30.0 | $380.9 | $301.5 | $591.9 | $254.8 | $1,747.9 |
| Purchased power (2) | 1,840.8 | 100.3 | 113.4 | 117.6 | 117.8 | 118.0 | 1,273.7 |
| Coal, biomass, oil and natural gas supply | 1,188.1 | 233.0 | 159.9 | 109.5 | 63.4 | 22.4 | 599.9 |
| Pension and post-retirement obligations (3) | 757.9 | 66.3 | 67.3 | 66.9 | 60.1 | 51.5 | 445.8 |
| Asset retirement obligations | 361.1 | 5.3 | 2.3 | 2.4 | 2.0 | 3.1 | 346.0 |
| Transportation (4) | 150.0 | 72.5 | 29.3 | 26.8 | 16.5 | 2.2 | 2.7 |
| Long-term service agreements (5) | 35.1 | 12.2 | 11.3 | 6.1 | 5.0 | 0.5 | - |
| Capital projects | 78.2 | 56.3 | 3.5 | 0.6 | 3.9 | - | 13.9 |
| Leases (6) | 32.3 | 3.9 | 3.3 | 3.2 | 3.1 | 2.8 | 16.0 |
| Other | 18.2 | 5.2 | 3.8 | 3.6 | 3.6 | 1.0 | 1.0 |
| | $7,768.7 | $585.0 | $775.0 | $638.2 | $867.3 | $456.3 | $4,446.9 |

(1) Long-term debt: Emera's and NSPI's revolving credit facilities mature in June 2015.
(2) Purchased power: annual requirement to purchase 100 percent of electricity production from independent power producers over varying contract lengths up to 25 years.
(3) Pension and post-retirement obligations: are based on regulatory requirements and assume that members stop accruing service effective December 31, 2011. As most of Emera's defined benefit pension plans still allow continued accrual of service and each plan's contribution requirements are reassessed on a regular basis, actual future pension contributions will differ from the amounts shown.
(4) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on various pipelines.
(5) Long-term service agreements: outsourced management of the Company's computer and communication infrastructure, vegetation management and maintenance of certain generation equipment.
(6) Leases: operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

## Capital Expenditures

Capital expenditures for 2011, including AFUDC, were approximately $515 million and included:

- $320 million in NSPI;
- $100 million in Maine Utility Operations;
- $70 million in Caribbean Utility Operations; and
- $25 million in Services, Renewables and Other Investments.

## Forecasted Gross Consolidated Capital Expenditures

| For the year ended December 31, 2012 millions of Canadian dollars | NSPI | Maine Utility Operations | Caribbean Utility Operations | Services, Renewable and other investments | Corporate | Total |
|---|---|---|---|---|---|---|
| Generation | $142 | NA | $45 | $13 | - | $200 |
| Transmission | 68 | $83 | 11 | 100 | - | 262 |
| Distribution | 72 | 18 | 3 | - | - | 93 |
| Facilities, equipment, vehicles and other | 48 | 16 | 4 | - | - | 68 |
| Total | $330 | $117 | $63 | $113 | - | $623 |

### Significant Individual Capital Projects

| millions of Canadian dollars | Nature of Project | Pre-2012 Spending | 2012 Forecast | Post-2012 Forecast | Expected year of completion |
|---|---|---|---|---|---|
| NSPI | Port Hawkesbury Biomass | $143 | $56 | $8 | 2013 |
| | Transmission | - | 1 | 11 | 2013 |
| | LED Streetlight Conversion | - | 6 | 94 | 2016 |
| | Marshall Falls Hydro Upgrade | - | 3 | 15 | 2017 |
| Maine Utility Operations | Transmission | 65 | 45 | 79 | 2012 – 2014 |
| | Technology | 3 | 11 | 7 | 2014 |
| Caribbean Utility Operations | West Sunrise Plant | 41 | 38 | - | 2012 |
| Services, Renewables and other investments | Bayside Power Gas Turbine Upgrade | 9 | 13 | 4 | 2012 |
| | Maritime Link Project | 10 | 30 | 1,160 | 2017 |
| | Labrador-Island Transmission Project | - | 70 | 530 | 2017 |

# PENSION FUNDING

For funding purposes, Emera determines required contributions to its largest defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three year period. The cash required in 2012 for defined benefit pension plans will be approximately $73.7 million (2011 – $51.9 million actual). All pension plan contributions are tax deductible and will be funded with cash from operations.

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

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

Emera's projected contributions to defined contribution pension plans are $6.5 million for 2012 (2011 – $6.2 million actual).

# OFF-BALANCE SHEET ARRANGEMENTS

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

Emera had the following guarantees and letter of credits as at December 31, 2011:

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

- Emera has provided a guarantee to LIPA on behalf of Bear Swamp for Bear Swamp's long-term energy and capacity supply agreement ("Agreement") with LIPA, which expires on April 30, 2021. The guarantee is for 50 percent of the relevant obligations under the Agreement up to a maximum of $18.6 million USD. As at December 31, 2011, the fair value of the Agreement is positive.

- Emera has provided a guarantee to the Bank of Nova Scotia on behalf of Bear Swamp for Bear Swamp's interest rate swaps entered into between Bear Swamp and the Bank of Nova Scotia which expires on May 9, 2012. The guarantee is for 50 percent of the relevant obligations up to a maximum of $1.0 million USD. In the event Emera was required to make a payment to the Bank of Nova Scotia under this guarantee, the guarantee provides that Emera is able to seek recovery from Bear Swamp's creditors after Bear Swamp has paid its debts in full. As at December 31, 2011, the fair value of that agreement is positive.

- At the request of Emera and its subsidiaries, a financial institution has issued standby letters of credit in the amount of $11.4 million for the benefit of third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one year term and are renewed annually as required.

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

- A financial institution has issued a standby letter of credit to secure obligations under an unfunded pension plan in BHE. The letter of credit expires in October 2012 and is renewed annually. The amount committed as at December 31, 2011 was $2.2 million USD.

- A financial institution has been issued direct pay letters of credit totaling $23.9 million USD to secure principal and interest payments related to Maine Public Utilities Financing Bank bonds issued on behalf of MPS, related to qualifying distribution assets.

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

# TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera purchased natural gas transportation capacity from M&NP, an investment under significant influence of the Company, totaling $10.6 million (2010 – $12.8 million) for the three months ended December 31, 2011, and $47.3 million (2010 – $55.1 million) for the year ended December 31, 2011. The amount is recognized in “Regulated fuel for generation and purchased power” or netted against energy marketing margin in “Non-regulated operating revenues” and is measured at the exchange amount. As at December 31, 2011, the amount payable to the related party was $3.3 million (December 31, 2010 – $3.9 million), and is under normal interest and credit terms.

# DIVIDENDS AND PAYOUT RATIOS

Emera Incorporated’s common dividend rate was $1.31 ($0.3250 per quarter in Q1, Q2 and Q3 and $0.3375 in Q4) per common share in 2011 and $1.16 ($0.2725 in Q1, $0.2825 in Q2 and Q3 and $0.3250 in Q4) per common share in 2010, representing a payout ratio of approximately 65.8 percent in 2011 and 69.2 percent in 2010.

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

In February 2010, the Board of Directors approved a quarterly dividend increase, effective May 3, 2010, to $0.2825 per common share, and in September 2010, approved a further increase to $0.3250 effective November 1, 2010 reflecting an increase on an annualized basis to $1.30 per common share.

Effective September 25, 2009, Emera changed its Common Shareholders Dividend Reinvestment and Share Purchase Plan to provide for a discount of up to 5 percent from the average market price of Emera’s common shares for common shares purchased in connection with the reinvestment of cash dividends under this Plan.

# RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

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

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

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

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and can be proven to effectively hedge the identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to Accumulated Other Comprehensive Loss (“AOCL”) and recognized in income in the same period the related hedged item is realized. Any ineffective portion of the change in the fair value of the cash flow hedges is recognized in net income in the reporting period.

Where the documentation or effectiveness requirements are not met, the derivatives are recognized at fair value, with any changes in fair value recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

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

Derivatives that do not meet any of the above criteria are designated as HFT and are recognized on the balance sheet at fair value. All gains and losses are recognized in net income of the period unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category when another accounting treatment applies.

**Hedging Items Recognized on the Balance Sheets**

The Company has the following categories on the balance sheet related to derivatives in valid hedging relationships:

| As at<br>millions of Canadian dollars | **December 31<br>2011** | December 31<br>2010<br>(adjusted) |
|---|---|---|
| Derivative instrument assets (current and other assets) | **$5.7** | $7.0 |
| Derivative instrument liabilities (current and long-term liabilities) | **(27.8)** | (18.3) |
| Net derivative instrument liabilities | **$(22.1)** | $(11.3) |

### Hedging Impact Recognized in Net Income

The Company recognized the following gains (losses) related to the effective portion of hedging relationships under the following categories:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | |
|---|---|---|---|---|
| | **2011** | 2010<br>(adjusted) | **2011** | 2010<br>(adjusted) |
| Regulated operating revenues | **$0.3** | - | **$2.7** | - |
| Non-regulated fuel and purchased power | **(2.3)** | $(2.1) | **(7.0)** | $(8.6) |
| Other income (expenses), net | **(0.2)** | - | **(0.3)** | - |
| Effectiveness net losses | **$(2.2)** | $(2.1) | **$(4.6)** | $(8.6) |

The effectiveness gains (losses) reflected in the above table would be offset in net income by the change in the hedged item realized in the period.

The Company recognized in net income the following gains (losses) related to the ineffective portion of hedging relationships under the following categories:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | |
|---|---|---|---|---|
| | **2011** | 2010<br>(adjusted) | **2011** | 2010<br>(adjusted) |
| Non-regulated fuel and purchased power | **$0.5** | - | **$(0.4)** | - |
| Ineffectiveness gains (losses) | **$0.5** | - | **$(0.4)** | - |

### Regulatory Items Recognized on the Balance Sheets

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

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

### Regulatory Impact Recognized in Net Income

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

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

**Held-for-trading Items Recognized on the Balance Sheets**

The Company has the following categories on the balance sheet related to HFT derivatives:

| As at<br>millions of Canadian dollars | **December 31<br>2011** | December 31<br>2010<br>(adjusted) |
|---|---|---|
| Derivative instruments assets (current and other assets) | **$16.7** | $18.8 |
| Derivative instruments liabilities (current and long-term liabilities) | **(14.7)** | (13.2) |
| Net derivative instrument assets | **$2.0** | $5.6 |

**Held-for-trading Items Recognized in Net Income**

The Company has recognized the following realized and unrealized gains (losses) with respect to HFT derivatives in net income:

| For the<br>millions of Canadian dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | |
|---|---|---|---|---|
| | **2011** | 2010<br>(adjusted) | **2011** | 2010<br>(adjusted) |
| Non-regulated operating revenues | **$4.0** | $6.2 | **$14.0** | $21.2 |
| Other income (expenses), net | **0.2** | 0.9 | **(0.1)** | 2.7 |
| Net gains | **$4.2** | $7.1 | **$13.9** | $23.9 |

# Business Risks

## Measurement of Risk

Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach. Certain risk management activities for Emera are overseen by the Enterprise Risk Management Committee to ensure such risks are appropriately assessed, monitored and controlled within predetermined risk tolerances established through approved policies.

The Company's risk management activities are focused on those areas that most significantly impact profitability, quality of income and cash flow. These risks include, but are not limited to, exposure to commodity prices, foreign exchange, acquisition risk, interest rates, commercial relationships, credit, labour, weather and regulatory risks, and changes in environmental legislation.

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

## Commodity Price Risk

A large portion of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts. In addition, the adoption and implementation of FAMs in certain subsidiaries has further helped manage this risk.

**Coal/Petroleum Coke**

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

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

**Heavy Fuel Oil**

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

BLPC and GBPC do not use derivatives to manage the changes in market price of heavy fuel oil. GBPC pays the spot market rate, and BLPC's fuel pricing is based on the three-day average market price.

**Natural Gas**

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

2012 – 83 percent
2013 – 31 percent

**Foreign Exchange Risk**

The Company enters into foreign exchange forward and swap contracts to limit exposure on foreign currency transactions such as fuel purchases, revenue streams and capital expenditures.

**NSPI**

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

**Bayside Power**

Bayside Power uses foreign exchange forward contracts to hedge the currency risk for capital projects denominated in foreign currencies. Forward contracts to buy €9.6 million were in place as at December 31, 2011 at a weighted average rate of $1.3770 for capital projects in 2012. Forward contracts to buy €2.8 million were in place as at December 31, 2011 at a weighted average rate of $1.3951 for capital projects in 2015.

### Brunswick Pipeline

Brunswick Pipeline uses forward contracts to hedge the currency risk associated with revenue streams denominated in foreign currencies. Forward contracts to sell $53.8 million USD in 2012 were in place as at December 31, 2011 at an average rate of $1.0654 and sell $78 million USD in 2013 through 2016 at a weighted average rate of $1.0591. These contracts cover 95 percent of anticipated USD revenue inflows in 2012 and 33 percent of anticipated USD revenue inflows in 2013 through 2016.

## Acquisition Risk

The risks associated with Emera's acquisition strategy include the availability of suitable acquisition candidates, obtaining the necessary regulatory approval for any acquisition and assimilating and integrating acquired companies into the Company. In addition, potential difficulties inherent in acquisitions may adversely affect the results of an acquisition. These include delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies from completed transactions.

Emera mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

## Interest Rate Risk

Emera utilizes a combination of fixed and variable rate debt financing for operations and capital expenditures resulting in an exposure to interest rate risk. The Company seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt. Floating-rate debt is estimated to represent approximately 15 percent of total debt in 2012. The Company has two interest rate hedging contracts outstanding as at December 31, 2011, fixing the variable interest rates on $22.6 million USD of Maine Public Utilities Financing Bank bonds at MPS.

## Commercial Relationships Risk

### NSPI

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

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

### Brunswick Pipeline

Brunswick Pipeline has a 25 year firm service agreement with Repsol Energy Canada ("REC"). The pipeline was used solely in 2011 and 2010 to transport natural gas from the Canaport LNG terminal in Saint John, New Brunswick to the United States border for REC. The risk of non-payment is mitigated as Repsol YPF, S.A ("Repsol"), the parent company of REC, has provided Brunswick Pipeline with a guarantee for all RECs' payment obligations under the firm service agreement. As at December 31, 2011 the net investment in direct financing lease with Repsol was $493.8 million. Repsol is rated investment grade BBB/Baa1; credit ratings and other company information are monitored on an ongoing basis. There is currently no allowance for credit losses related to this agreement.

### Bayside Power

Bayside Power sells all its generation during the months of November through March to NB Power in accordance with a long-term purchase power agreement ("PPA"). Revenue from this PPA contributed 46.5 percent (2010 – 48.0 percent) to Bayside Power's electric revenues for the year ended December 31, 2011. The PPA expires March 31, 2021, with an option to renew for an additional five year term, provided both parties consent to the renewal.

## Credit Risk

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

## Labour Risk

Certain Emera employees are subject to collective labour agreements. Approximately 55 percent of the full-time and term employees at NSPI, BLPC, GBPC, Bangor Hydro, EUS, and MPS are represented by local unions. Approximately 45 percent of the labour force is covered by collective labour agreements that will expire within the next twelve months. Emera seeks to manage this risk through ongoing discussions with the local unions.

## Weather Risk

Shifts in weather patterns affect electric sales volumes and associated revenues. Extreme weather events generally result in increased operating costs associated with restoring power to customers. Emera responds to significant weather event related outages according to each subsidiary's respective Emergency Services Restoration Plan.

## Regulatory Risk

The Company's rate-regulated subsidiaries are subject to risk in the recovery of costs and investments in a timely manner. The Company manages this risk through ongoing stakeholder consultation and engagement on aspects such as utility operations, rate filings and capital plans.

### NSPI

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

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

**Bangor Hydro**

Bangor Hydro's business consists of three primary components which are each governed by their own regulatory structure. The components include distribution, transmission and stranded cost recoveries.

Distribution Operations

Bangor Hydro's distribution business operates under the regulation of the MPUC and operates under a traditional cost-of-service regulatory structure. Distribution rates are set based on an allowed ROE of 10.2 percent, on a common equity component of 50 percent.

Transmission Operations

Bangor Hydro's local transmission rates are set by the FERC annually on June 1, based upon a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted transmission investments and expenses. The allowed ROE for these local transmission investments is 11.14 percent. The common equity component is based upon the prior calendar year actual average balances. On June 1, 2011, Bangor Hydro's local transmission rates decreased by approximately 10 percent (2010 - increased 37 percent).

Bangor Hydro's bulk transmission assets are managed by the ISO-New England ("ISO") as part of a region-wide pool of assets. The ISO manages the regions' bulk power generation and transmission systems and administers the open access transmission tariff. Currently, Bangor Hydro, along with all other participating transmission providers, recovers the full cost of service for their transmission assets, from distribution companies in New England, based on a regional formula that is updated on June 1 of each year. This formula is based on prior year regionally funded transmission investments and expenses, adjusted for current year forecasted investments and expenses. Bangor Hydro's allowed ROE for these transmission investments ranges from 11.64 percent to 12.64 percent, and the common equity component is based upon the prior calendar year average balances. The participating transmission providers are also required to contribute to the cost of service of such transmission assets on a ratable basis according to the proportion of the total New England load that their customers represent.

On June 1, 2010, Bangor Hydro's regional transmission revenue requirement increased by 22 percent; and on June 1, 2011, it increased by a further 9 percent.

Stranded Cost Recoveries

Electric utilities in Maine are entitled to recover all prudently incurred stranded costs resulting from the restructuring of the industry in 2000 that could not be mitigated or that arose as a result of rate and accounting orders issued by the MPUC. Generally, the regulatory rates to recover stranded costs are set every three years on a levelized basis and determined under a traditional cost of service approach.

In May 2011, the MPUC approved an approximate 27 percent increase in Bangor Hydro's stranded cost rates for the period of June 1, 2011 to February 28, 2014. The increased stranded cost revenues are offset, for the most part, by changes in regulatory amortizations, purchased power expense and resale of purchased power. The allowed ROE used in setting these new stranded cost rates is 7.4 percent, with a common equity component of 48 percent.

While the stranded cost revenue requirements differ throughout the period due to changes in annual stranded costs, the actual annual stranded cost revenues are the same during the period. To levelize the impact of the varying revenue requirements, cost or revenue deferrals are recorded as a regulatory asset or liability, and addressed in subsequent stranded cost rate proceedings, where customer rates are adjusted accordingly.

**MPS**

Similar to Bangor Hydro, MPS' business consists of three primary components which are each governed by their own regulatory structure. The components are distribution, transmission and stranded cost recoveries.

Distribution Operations

MPS' distribution business operates under the regulation of the MPUC and operates under a traditional cost-of-service regulatory structure. Distribution rates are set based on an allowed ROE of 10.2 percent, on a common equity component of 50 percent.

Transmission Operations

MPS local transmission rates are set annually based on a formula through its OATT. Rates derived from the previous calendar year results go into effect June 1 for wholesale customers and July 1 for retail customers. The allowed ROE for transmission operations is 10.5 percent, and is based on the actual prior calendar year common equity balances. The allowed ROE is determined by negotiation with customers in the formula change years of the OATT, which occur every three years. The last OATT formula change year was 2009. On June 1, 2011, MPS' local transmission rates increased by 3 percent for wholesale customers (2010 – increased 63 percent) and by 4 percent for retail customers (2010 – increased by 64 percent) on July 1, 2011.

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

Stranded Cost Recoveries

In December 2011, the MPUC approved MPS' stranded cost rates for the three-year period January 1, 2012 through December 31, 2014. This revised three-year agreement, which amortizes essentially all of MPS' remaining stranded costs, has an ROE of 7.2 percent and a common equity component of 50 percent. Any residual stranded costs remaining after December 31, 2014 will be recovered in future rate proceedings.

**The Barbados Light & Power Company Limited**

BLPC, a wholly-owned subsidiary of LPH, is the sole electric utility on the island of Barbados. BLPC is subject to regulation under the Utilities Regulation (Procedural) Rules 2003 ("Rules") by Fair Trading Commission, Barbados, an independent regulator. The Rules give the Fair Trading Commission, Barbados utility regulation functions which include establishing principles for arriving at rates to be charged, monitoring the rates charged to ensure compliance, and setting the maximum rates for regulated utility services. The government of Barbados has granted BLPC a franchise to produce, transmit and distribute electricity on the island until 2028.

BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and providing an appropriate return to investors. BLPC's approved regulated return on assets for 2011 is 10 percent.

BLPC's first rate adjustment since 1983 was approved in January 2010 and was effective March 1, 2010.

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

BLPC has the ability to carryover an under-recovery to later months to smooth the fuel surcharge for customers.

**Grand Bahama Power Company Limited**

GBPC is the sole utility operator on Grand Bahama Island. GBPA regulates the utility and has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit, and distribute electricity on the island until 2054. There is a fuel pass through mechanism and flexible tariff adjustment policy to ensure that costs are recovered and a reasonable return earned.

The base tariff for GBPC includes a component to recover the cost of $20 USD per barrel of oil consumed by GBPC for generation of electricity. The amount by which actual fuel costs exceed $20 USD dollars per barrel is recovered or rebated through the fuel surcharge, which is adjusted on a monthly basis. The methodology for calculating the amount of the fuel surcharge has been approved by GBPA.

## Changes in Environmental Legislation

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

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

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

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

**Climate Change and Air Emissions**

Greenhouse Gas Emissions

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

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

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

Renewable Energy

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

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

**Mercury, Nitrogen Oxide and Sulphur Dioxide Emissions**

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

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

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

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

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

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

# DISCLOSURE AND INTERNAL CONTROLS

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

As permitted, the Company has limited the scope of its design of DC&P and ICFR by excluding the controls, policies and procedures at LPH, which was acquired on January 25, 2011. Summary financial information about the acquisition is included in Note 18 of the Consolidated Financial Statements as at and for the year ended December 31, 2011 and 2010. The relative size of the entity has not materially changed since its acquisition dates.

Pursuant to Section 404(c) of the Sarbanes-Oxley Act of 2002 (“SOX”), as added by Section 989G of the Dodd-Frank Wall Street Reform and Consumer Protection Act, the requirement under Section 404(b) of SOX to file an auditor attestation report on an issuer’s ICFR does not apply with respect to any audit report prepared for an issuer that is neither an accelerated filer nor a large accelerated filer, as defined in Rule 12b-2 under the Exchange Act. NSPI is currently not an accelerated filer or a large accelerated filer and, therefore, is not required to file attestation reports on its ICFR. As previously noted, in December 2011, NSPI made the necessary filings to terminate its SEC reporting obligations. As a new registrant, Emera is not required to include an attestation report on its ICFR in its first Annual Report to be filed with the SEC for the year ending December 31, 2011, but would be required to include an attestation report in its subsequent Annual Reports for any year in which it is an accelerated filer or a large accelerated filer.

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

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

# SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

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

## Rate Regulation

The rate-regulated accounting policies of NSPI, Bangor Hydro, MPS, BLPC, GBPC and Brunswick Pipeline may differ from accounting policies for non-rate-regulated companies. NSPI, Bangor Hydro, MPS, BLPC and GBPC accounting policies are subject to examination and approval by their respective regulators. These accounting policy differences occur when the regulators render their decisions on rate applications or other matters and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on the expectation of the future actions of the regulators.

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

## Pension and Other Post-Retirement Employee Benefits

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

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

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

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

Emera's accounting policy is to amortize the net actuarial gain or loss, which exceeds 10 percent of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period, which is currently 9 years.  Emera's use of smoothed asset values further reduces the volatility related to the amortization of actuarial investment experience.  As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

The discount rate used to determine benefit costs is based on the yield of high quality long-term corporate bonds in each operating entity's country.  The discount rate is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year rounded to the nearest 25 basis points.  For benefit cost purposes, NSPI's rate was 5.50 percent for 2011 (2010 – 6.50 percent) and Bangor Hydro's rate was 5.60 percent for 2011 (2010 – 6.00 percent).  MPS' rate was 5.40 for 2011 (2010 – 5.75 percent) and GBPC's rate for 2011 was 6.00 percent (2010 – 6.00 percent).

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts.  The benefit cost calculations assumed that plan assets would earn a rate of return of 7.00 percent for 2011 (2010 – 7.25 percent) for NSPI and 8.00 percent for 2011 and 2010 for Bangor Hydro.  The assumed rate of return on plan assets for 2011 and 2010 was 8.50 percent for MPS and 6.00 percent for 2011 and 2010 for GBPC.

The reported benefit cost for 2011, based on management's best estimate assumptions, is $55.7 million. While there are numerous assumptions which are used to determine the benefit cost, the discount rate and asset return assumptions have an impact on the calculations.

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

| | 0.25% Increase | | 0.25% Decrease | |
|---|---|---|---|---|
| millions of dollars | 2011 | 2010 | 2011 | 2010 |
| Discount rate assumption | $(3.9) | $(3.5) | $4.0 | $3.6 |
| Asset return assumption | $(2.0) | $(1.8) | $2.0 | $1.8 |

## Unbilled Revenue

Electric revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for Bangor Hydro, MPS, BLPC and GBPC.  At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and of related revenues earned but not yet billed.  The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses and applicable customer rates.  EUS includes an estimate of work completed under contracts but not yet billed at the end of each month.  Brunswick Pipeline also makes an estimate of toll revenues at the end of each month.  Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate.  As at December 31, 2011, unbilled revenues amount to $133.6 million (2010 – $126.4 million) on a base of annual operating revenues of approximately $2,064.4 million (2010 – $1,606.1 million).

## Property, Plant and Equipment

Property, plant and equipment represents 62.0 percent of total assets recognized on the Company's balance sheet. Included in "Property, plant and equipment" are the generation, transmission and distribution and other assets of the Company. Due to the magnitude of the Company's property, plant and equipment, changes in estimated depreciation rates can have a material impact on depreciation expense.

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

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

## Income Taxes

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

## Asset Retirement Obligations

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

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

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

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

| Asset | Credit-adjusted risk-free rate | | Estimated undiscounted future obligation (millions of dollars) | | Expected settlement date (number of years) | |
|---|---|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 | **2011** | 2010 |
| Thermal | **5.1 – 5.3%** | 5.2 – 5.3% | **$142.8** | $258.9 | **21 – 32** | 10 – 29 |
| Hydro | **5.1 – 5.3%** | 5.2 – 5.3% | **127.6** | 101.4 | **20 – 50** | 21 – 51 |
| Wind | **5.1 – 5.2%** | 5.2% | **27.4** | 45.5 | **17 – 24** | 13 – 20 |
| Combustion turbines | **5.1 – 5.3%** | 5.2 – 5.3% | **8.3** | 12.9 | **5 – 34** | 1 – 14 |
| Transmission & distribution | **4.3 – 5.8%** | 5.7% | **30.4** | 21.6 | **1 – 14** | 1 – 15 |
| Pipeline | **3.50%** | 3.80% | **24.6** | 11.0 | **38** | 39 |
| | | | **$361.1** | $451.3 | | |

As at December 31, 2011, the AROs recorded on the balance sheet were $99.9 million (2010 – $141.8 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $358.1 million, which will be incurred between 2012 and 2062. The majority of these costs will be incurred between 2032 and 2047.

### Goodwill Impairment Assessments

Goodwill represents the excess of the acquisition purchase price for Bangor Hydro, GBPC, ICDU and MAM over the fair values assigned to individual assets acquired and liabilities assumed. Emera is required to perform an impairment assessment annually, or in the interim if an event occurs that indicates the fair value of Bangor Hydro, GBPC, ICDU or MAM may be below its carrying value. Emera performs its annual impairment test as at October 1.

Emera's reporting units will first assess qualitative factors to determine whether it is more likely than not that the assets' fair value is less than the carrying amount, in which case it is necessary to perform the quantitative goodwill impairment test. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. There was no impairment provision required in 2011 or 2010.

# CHANGES IN ACCOUNTING POLICIES AND PRACTICES

## Future Accounting Pronouncements

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

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

*Other Comprehensive Income, ASU No. 2011-05*

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

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

*Fair Value Measurement, ASU No. 2011-04*

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

# SUMMARY OF QUARTERLY RESULTS

| For the quarter ended millions of dollars (except per share amounts) | **Q4 2011** | Q3 2011 | Q2 2011 | Q1 2011 | Q4 2010 (adjusted) | Q3 2010 (adjusted) | Q2 2010 (adjusted) | Q1 2010 (adjusted) |
|---|---|---|---|---|---|---|---|---|
| Total operating revenues | **$512.0** | $496.1 | $501.7 | $554.6 | $408.9 | $394.0 | $364.7 | $438.5 |
| Net income attributable to common shareholders | **46.8** | 40.8 | 29.9 | 123.6 | 24.1 | 40.3 | 48.5 | 77.8 |
| Earnings per common share – basic | **0.38** | 0.33 | 0.24 | 1.06 | 0.21 | 0.35 | 0.43 | 0.68 |
| Earnings per common share – diluted | **0.38** | 0.33 | 0.24 | 1.03 | 0.21 | 0.35 | 0.42 | 0.67 |

Quarterly total operating revenues and net income attributable to common shareholders are affected by seasonality. Q1 and Q4 are generally the strongest because a significant portion of the Company's operations are located in northeast North America, where winter is the peak electricity season. Quarterly results are also affected by items outlined in the Significant Items section.

# OPERATING STATISTICS (Unaudited)

## FIVE-YEAR SUMMARY

| Year Ended December 31 | **2011** | 2010 (adjusted) | 2009 (adjusted) | 2008 (adjusted) | 2007 (adjusted) |
|---|---|---|---|---|---|
| Electric energy sales (GWh) | | | | | |
| Residential | **5,458.9** | 4,738.2 | 4,819.2 | 4,769.6 | 4,738.5 |
| Commercial | **6,562.3** | 5,584.4 | 3,694.4 | 3,721.1 | 3,768.5 |
| Industrial | **3,988.5** | 4,268.2 | 3,985.3 | 4,491.5 | 4,568.4 |
| Other | **347.0** | 620.1 | 1,166.9 | 652.2 | 655.4 |
| Total electric energy sales | **16,356.7** | 15,210.9 | 13,665.8 | 13,634.4 | 13,730.8 |
| Sources of energy (GWh) | | | | | |
| Thermal – coal | **6,848.0** | 7,838.7 | 8,177.3 | 9,008.9 | 9,561.4 |
| – oil | **1,070.8** | 36.1 | 306.9 | 340.7 | 516.6 |
| – natural gas | **4,304.7** | 4,183.0 | 2,141.4 | 1,257.9 | 1,057.1 |
| Hydro | **1,414.5** | 991.5 | 1,063.4 | 1,065.3 | 908.8 |
| Wind | **247.0** | 25.3 | 1.8 | 2.4 | 2.4 |
| Purchases | **3,518.3** | 2,987.4 | 2,846.1 | 2,874.5 | 2,654.7 |
| Total generation and purchases | **17,403.3** | 16,062.0 | 14,536.9 | 14,549.7 | 14,701.0 |
| Losses and internal use | **1,046.6** | 851.1 | 871.1 | 915.3 | 970.2 |
| Total electric energy sold | **16,356.7** | 15,210.9 | 13,665.8 | 13,634.4 | 13,730.8 |
| Electric customers | | | | | |
| Residential | **696,970** | 588,935 | 539,333 | 535,494 | 530,955 |
| Commercial | **79,817** | 61,620 | 51,768 | 54,461 | 51,083 |
| Industrial | **2,517** | 2,558 | 2,543 | 2,541 | 2,543 |
| Other | **10,446** | 9,422 | 9,155 | 9,064 | 9,574 |
| Total electric customers | **789,750** | 662,535 | 602,799 | 601,560 | 594,155 |
| Capacity | | | | | |
| Generating nameplate capacity (MW) | | | | | |
| Coal fired | **1,243** | 1,243 | 1,243 | 1,243 | 1,243 |
| Dual fired | **350** | 350 | 350 | 365 | 350 |
| Gas turbines | **666** | 599 | 564 | 289 | 304 |
| Hydroelectric | **395** | 395 | 395 | 395 | 395 |
| Wind turbines | **82** | 76 | 1 | 1 | 1 |
| Diesel | **173** | 61 | 15 | 15 | 15 |
| Steam | **47** | 51 | - | - | - |
| Independent power producers | **264** | 347 | 172 | 120 | 120 |
| | **3,220** | 3,122 | 2,740 | 2,428 | 2,428 |
| Total number of employees | **3,458** | 2,972 | 2,350 | 2,215 | 2,194 |
| km of transmission lines | **6,800** | 6,700 | 6,300 | 6,400 | 6,100 |
| km of distribution lines | **41,600** | 40,900 | 33,800 | 32,600 | 32,000 |

| **REGULATED ELECTRIC** | Customers | Employee Count | Peak Demand (MW) | Energy Sales (Gwh) | Total Assets (billions) | Rate Base (billions) | Income (millions) | Allowable ROE 2011 | Allowable ROE 2010 |
|---|---|---|---|---|---|---|---|---|---|
| NSPI | 493,183 | 1,883 | 2,168 | 11,206 | $3.9 | $3.5 | $123.5 | 9.1-9.6% | 9.1-9.6% |
| Bangor Hydro | 118,080 | 295 | 290.9 | 1,520.5 | 0.82 | 0.50 | 34.2 | 11.21% | 11.18% |
| MPS | 36,293 | 127 | 102.1 | 496.3 | 0.14 | 0.06 | 2.8 | 9.69% | 9.76% |
| BLPC | 122,900 | 500 | 160.1 | 934.6 | 0.5 | 0.3 | 14.0 | 10.0% | - |
| GBPC | 19,180 | 174 | 64.1 | 328.3 | 0.2 | - | 5.2 | - | - |

# THREE YEAR FINANCIAL SUMMARY

| For the year ended December 31 (millions of Canadian dollars) | **2011** | 2010 (adjusted) | 2009 (adjusted) |
|---|---|---|---|
| **Consolidated Statements of Income** | | | |
| Operating revenues | **$2,064.4** | $1,606.1 | $1,490.1 |
| Operating expenses | | | |
| Regulated fuel for generation and purchased power | **866.4** | 634.6 | 550.0 |
| Regulated fuel adjustment | **(8.5)** | (99.0) | 8.5 |
| Non-regulated fuel for generation and purchased power | **73.9** | 83.9 | 29.5 |
| Non-regulated direct costs | **60.9** | 62.3 | 37.9 |
| Operating, maintenance and general | **455.0** | 351.2 | 299.1 |
| Provincial, state and municipal taxes | **49.2** | 47.4 | 48.0 |
| Depreciation and amortization | **250.0** | 213.5 | 199.7 |
| Income from operations | **317.5** | 312.2 | 317.4 |
| Income from equity investments and other income (expenses), net | **64.6** | 27.8 | 49.3 |
| Interest expense, net | **159.4** | 148.8 | 132.8 |
| Income before provision for income taxes | **222.7** | 191.2 | 233.9 |
| Income tax expense (recovery) | **(36.7)** | (8.1) | 37.4 |
| Net income | **259.4** | 199.3 | 196.5 |
| Non-controlling interest in subsidiaries | **11.7** | 5.6 | 10.2 |
| Net income of Emera Incorporated | **247.7** | 193.7 | 186.3 |
| Preferred stock dividends | **6.6** | 3.0 | - |
| Net income attributable to common shares | **241.1** | 190.7 | 186.3 |
| **Balance Sheets Information** | | | |
| Current assets | **993.3** | 840.1 | 811.5 |
| Property, plant and equipment, net of accumulated depreciation | **4,294.4** | 3,742.6 | 3,104.2 |
| Other assets | | | |
| Deferred income taxes | **33.1** | 31.1 | 66.2 |
| Derivative instruments | **39.6** | 36.0 | 45.4 |
| Regulatory assets | **312.2** | 354.9 | 278.8 |
| Net investment in direct financing lease | **492.0** | 491.5 | 480.1 |
| Investments subject to significant influence | **222.7** | 246.0 | 216.3 |
| Available-for-sale investments | **54.6** | 0.8 | 1.0 |
| Intangibles, net of accumulated amortization | **100.7** | 98.7 | 93.0 |
| Goodwill | **197.7** | 167.4 | 87.6 |
| Other | **183.3** | 69.9 | 63.2 |
| Total assets | **6,923.6** | 6,079.0 | 5,247.3 |
| Current liabilities | **801.7** | 605.9 | 857.7 |
| Long-term liabilities | | | |
| Long-term debt | **3,273.5** | 3,115.3 | 2,272.7 |
| Deferred income taxes | **228.6** | 168.5 | 126.2 |
| Derivative instruments | **38.7** | 28.9 | 35.5 |
| Regulatory liabilities | **107.1** | 65.2 | 91.5 |
| Asset retirement obligations | **99.9** | 141.8 | 104.5 |
| Pension and post-retirement liabilities | **530.8** | 400.0 | 292.4 |
| Other long-term liabilities | **19.6** | 22.0 | 33.0 |
| Equity | | | |
| Common stock | **1,385.0** | 1,137.8 | 1,097.9 |
| Preferred stock | **146.7** | 146.7 | - |
| Contributed surplus | **3.3** | 3.2 | 3.0 |
| Accumulated other comprehensive loss | **(671.7)** | (564.2) | (426.2) |
| Retained earnings | **735.9** | 653.5 | 594.8 |
| Total Emera Incorporated equity | **1,599.2** | 1,377.0 | 1,269.5 |
| Non-controlling interest in subsidiaries | **224.5** | 154.4 | 164.3 |
| Total equity | **1,823.7** | 1,531.4 | 1,433.8 |
| Total liabilities and equity | **6,923.6** | 6,079.0 | 5,247.3 |
| Statements of Cash Flow Information | | | |
| Cash provided by operating activities | **399.5** | 419.2 | 318.1 |
| Cash used in investing activities | **(660.8)** | (886.0) | (380.8) |
| Cash provided by financing activities | **331.3** | 454.6 | 61.2 |
| Financial ratios ($ per share) | | | |
| Earnings per share | **$1.99** | $1.67 | $1.65 |