Management's Discussion & Analysis

As at February 17, 2010

Management's Discussion and Analysis ("MD&A") provides a review of the results of operations of Emera Inc. and its primary subsidiaries and investments during the fourth quarter of 2009 relative to 2008, and the full year 2009 relative to 2008 and to 2007; and its financial position at December 31, 2009 relative to 2008. To enhance shareholders' understanding, certain multi-year historical financial and statistical information is presented.

This discussion and analysis should be read in conjunction with the Emera Inc. annual audited consolidated financial statements and supporting notes. Emera Inc. follows Canadian Generally Accepted Accounting Principles ("CGAAP"), including the application of rate-regulated accounting policies for Emera Inc.'s rate-regulated subsidiaries. Emera Inc.'s wholly-owned subsidiaries, Nova Scotia Power Inc. ("NSPI"), Bangor Hydro-Electric Company ("Bangor Hydro") and Emera Brunswick Pipeline Company Ltd. ("Brunswick Pipeline") are subject to rate regulation and the accounting policies used by these entities may differ in regard to the timing of recognition of certain assets, liabilities, revenue and expenses, from those used by Emera Inc.'s non rate-regulated companies. NSPI's accounting policies are subject to examination and approval by the Nova Scotia Utility and Review Board ("UARB"). Bangor Hydro's accounting policies are subject to examination and approval by the Maine Public Utilities Commission ("MPUC") and the Federal Energy Regulatory Commission ("FERC").

Throughout this discussion, "Emera Inc." and "Emera" refer to Emera Inc. and all of its consolidated subsidiaries and affiliates.

All amounts are in Canadian dollars ("CAD") except for the Bangor Hydro 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.

Forward Looking Information

This MD&A contains forward-looking information and forward-looking statements which reflect the current view with respect to the company's objectives, plans, financial and operating performance, business prospects and opportunities. Certain factors that may affect future operations and financial performance are discussed, including information in the Outlook section of the MD&A. Wherever used, the words "may", "will", "intend", "estimate", "plan", "believe", "anticipate", "expect", "project" and similar expressions are intended to identify such forward-looking statements 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. Although Emera believes such statements are based on reasonable assumptions, such statements are subject to certain risks, uncertainties and assumptions pertaining to, but not limited to, operating performance, regulatory requirements, weather, general economic conditions, commodity prices, interest rates and foreign exchange. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary significantly from those expected. Emera disclaims any intention or obligation to update or revise any forward-looking information or forward-looking statements, whether as a result of new information, future events or otherwise, except as required under applicable securities laws.

Structure of MD&A

This MD&A begins with an introduction and strategic overview followed by a consolidated financial review including consolidated statements of earnings, balance sheets and cash flow highlights and outstanding share data; then presents information on NSPI, Bangor Hydro and Pipelines (includes Brunswick Pipeline and Maritimes & Northeast Pipeline). All other operations are grouped and discussed under Other and include Emera Energy (includes Bear Swamp and Bayside Power Limited Partnership); Caribbean (includes St. Lucia Electricity Services ("Lucelec") and Grand Bahama Power Company Limited ("GBPC")); and corporate activities. The following is presented on a consolidated basis: 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 and summary of quarterly results.

INTRODUCTION AND STRATEGIC OVERVIEW

Emera is a Canadian energy holding company headquartered in Halifax, Nova Scotia. The company invests in electricity generation, transmission and distribution as well as gas generation and transmission and energy marketing.

Approximately 94% of Emera's revenues are earned by NSPI, Bangor Hydro and Brunswick Pipeline. NSPI is a wholly-owned fully integrated regulated utility with $3.5 billion of assets which provides electricity generation, transmission and distribution services to approximately 486,000 customers in the province of Nova Scotia. Bangor Hydro is an electricity transmission and distribution company with $738 million of assets serving approximately 117,000 customers in eastern Maine. Both businesses operate as monopolies in their service territories. Brunswick Pipeline is a $500 million, 145-kilometre pipeline carrying re-gasified liquefied natural gas ("LNG") from the Canaport™ LNG terminal in Saint John, New Brunswick to the United States border. This regulated pipeline operates under a 25 year firm service agreement with Repsol Energy Canada. The success of Emera's primary businesses is integral to the creation of shareholder value, providing strong, predictable earnings and growing cash flow to fund dividends and reinvestment.

The remaining approximately 6% of Emera's revenues are earned by a growing group of strategic investments that are expected to contribute more significantly to Emera's earnings in the coming years. These are described in more detail in the Other section of the MD&A.

Emera's goal is to deliver annual consolidated earnings growth of 4% to 6%, and to build and diversify its earnings base with a focus on cleaner energy in its markets. Emera will continue to seek growth from its existing businesses and will leverage its core strength in the electricity business as it pursues both acquisitions and greenfield development opportunities in regulated electricity transmission and distribution and low risk generation. Emera's growth strategy also includes serving the North American and Caribbean markets by capitalizing on opportunities in related energy infrastructure businesses appropriate to its risk profile, where its development, commercial and operational skills are needed.

Although markets in Nova Scotia and Maine are otherwise mature, the transformation of energy supply to lower emission sources has created the opportunity for organic growth within NSPI and Bangor Hydro. Both companies expect earnings growth of 2% to 4% annually over the next five years as new investments are made in renewable generation and transmission.

Non-GAAP Measure

Emera uses a financial measure that does not have a standardized meaning under CGAAP. This financial measure is "Earnings per common share – basic, absent the Bear Swamp after-tax mark-to-market adjustment". Management discloses this financial measure as it believes the inclusion of the mark-to-market adjustment in Bear Swamp's financial results does not accurately reflect its operational performance. Many investors use this financial measure to assess Emera's overall financial performance.

CONSOLIDATED FINANCIAL REVIEW

Consolidated Financial Highlights

millions of dollars (except earnings per common share)	Three months ended December 31		Year ended December 31		
	2009	2008	**2009**	2008	2007
Revenues	**$389.1**	$337.3	**$1,465.5**	$1,331.9	$1,339.5
Consolidated net earnings	**37.5**	25.3	**175.7**	144.1	151.3
Earnings per common share – basic	**0.33**	0.23	**1.56**	1.29	1.36
Earnings per common share – diluted	**0.33**	0.22	**1.52**	1.26	1.32
Cash dividends declared per share	**0.2725**	0.2525	**1.03**	0.97	0.90

	Three months ended December 31		Year ended December 31		
Operating Unit Contributions	**2009**	2008	**2009**	2008	2007
NSPI	**$17.4**	$14.4	**$109.3**	$105.6	$100.2
Bangor Hydro	**7.0**	6.6	**27.5**	23.1	27.5
Pipelines	**8.4**	6.9	**24.2**	15.4	12.0
Other	**8.4**	(6.3)	**12.5**	1.6	21.4
Corporate costs and other	**(3.7)**	3.7	**2.2**	(1.6)	(9.8)
Consolidated net earnings	**$37.5**	$25.3	**$175.7**	$144.1	$151.3
Earnings per common share – basic	**$0.33**	$0.23	**$1.56**	**$1.29**	$1.36
Earnings per common share – basic, absent the Bear Swamp after-tax mark-to-market adjustment	**$0.30**	$0.26	**$1.55**	$1.33	$1.28

	As at December 31		
	2009	2008	2007
Total assets	**$5,293.2**	$5,269.4	$4,221.1
Total long-term liabilities	**2,979.6**	2,843.1	2,354.7

Developments

Dividends

In September 2009, the Board of Directors approved a quarterly dividend increase to $0.2725 per common share, reflecting an increase on an annualized basis to $1.09 per common share.

Effective September 25, 2009, Emera changed its Common Shareholders Dividend Reinvestment and Share Purchase Plan ("Plan") to provide for a discount of up to 5% from the average market price of Emera's common shares for common shares purchased in connection with the reinvestment of cash dividends under the Plan. The Board of Directors of Emera also decided that the discount would be 5% effective on and after the quarterly dividend payment on November 16, 2009, to shareholders of record on November 2, 2009.

Return on Equity Decision

In January 2010, NSPI reached an agreement with stakeholders on its calculation of regulated return on equity ("ROE"). The agreement establishes that NSPI will continue to use actual capital structure, actual equity and actual net earnings to calculate actual annual regulated ROE. The agreement further provides NSPI with flexibility in amortizing the pre-2003 income tax regulatory asset, allowing NSPI to recognize additional amortization amounts in current periods and reducing amounts in future periods. Accordingly, effective December 31, 2009, NSPI recognized an additional discretionary $10 million of regulatory amortization expense to allow flexibility relating to future customer rate requirements. The agreement was approved by the UARB. The UARB have set, as a condition, that NSPI will maintain its average regulated annual common equity at a level no higher than 40% in 2010 and until the next general rate case.

Nova Scotia Renewable Energy Standard Regulation

In January 2007, the Nova Scotia government approved the Renewable Energy Standard Regulation ("RES") to increase the percentage of renewable energy in the Nova Scotia generation mix. In October 2009, the RES was amended. The target date for 5% 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% of renewable energy, is unchanged. The renewable energy projects owned by independent power producers which are already in service, in combination with those which are scheduled for completion by the end of 2010, are expected to enable NSPI to be in compliance with the 2011 RES requirement.

Point Tupper Wind Development

In November 2009, to satisfy NSPI's requirements under the Province's 2011 Renewable Energy Standards, the company signed a project operating agreement with Renewable Energy Services Ltd. ("RESL"), an independent power producer, regarding the construction and operation of a 23-megawatt ("MW") wind farm in Richmond County, Nova Scotia. NSPI will own approximately 49% of the wind farm, with RESL constructing, managing, operating and maintaining the site. In order to facilitate this existing project's advancement, NSPI has provided a limited guarantee for the indebtedness of RESL. The guarantee is up to a maximum of $23.5 million. NSPI holds a first ranking security interest in the assets of RESL and all future assets of the project owned by RESL. NSPI had previously signed a power purchase agreement with RESL relating to the wind farm, which was one of the power purchase agreements NSPI signed with independent power producers to meet provincial regulations. NSPI is seeking the UARB's approval to include its portion of the project in regulated rate base.

Nuttby Mountain Wind Project

In April 2009, NSPI purchased the development rights for a proposed 45-MW wind farm located at Nuttby Mountain, Nova Scotia. The Nuttby Mountain project represented one of the power purchase agreements NSPI had signed with independent power producers previously. The Nuttby Mountain project development rights were owned by EarthFirst Nuttby Inc., a subsidiary of EarthFirst Canada Inc. The development rights included land leases and transmission interconnection rights as well as provincial environmental approval. As a result of the purchase by NSPI, this particular power purchase agreement is no longer in effect. The UARB approved the development of this project as a capital work order, and it will be included in regulated rate base at a cost of approximately $120 million.

Digby Wind Project

Emera has purchased 100% of a proposed 30-MW wind power project to be located in Digby County, Nova Scotia. Project assets acquired include development rights, a 20-year power purchase agreement with NSPI and rights to purchase 20 wind turbines. The project is expected to be completed by December 31, 2010, at a total cost of approximately $75 million.

Acquisition of Bayside Power Limited Partnership

On September 1, 2009, Emera's subsidiary, Emera Energy Inc., purchased 100% interest in Bayside Power Limited Partnership ("Bayside"), a 260-MW gas-fired combined cycle electricity generating facility, built in 1999, and located in Saint John, New Brunswick. Until March 31, 2021, Bayside has a contract to supply electricity for the months of November through March, and operates as a merchant facility selling into the Maritimes and northeastern United States markets for the balance of the year. Emera Energy

Inc. can, at its sole option, extend for an additional five years, through to March 31, 2026, the contract to supply energy for the months of November through March.

The transaction was financed with existing credit facilities. It is expected Bayside will be moderately accretive to Emera within the first year.

Strategic Partnership with Algonquin Power and Utilities Corp. (formerly Algonquin Power Income Fund)

In April 2009, Emera signed an agreement giving it the rights to acquire a 9.9% interest in Algonquin Power Income Fund ("APIF") through a private placement of 8.5 million APIF units for a purchase price of $27.7 million. Emera issued a promissory note in the principal amount of $27.7 million to APIF in exchange for 8.5 million subscription receipts which are convertible to APIF units upon the successful joint acquisition by Emera and APIF of the electricity distribution and related generation assets of Sierra Pacific Power Company. Christopher Huskilson, President and Chief Executive Officer, Emera Inc., was elected to the Board of Trustees of APIF at the July 27, 2009 meeting of APIF unitholders. The agreement also gives Emera rights to acquire a further 5% of APIF over the next two years.

Emera and APIF have committed to acquire the electricity distribution and related generation assets of Sierra Pacific Power Company for approximately $116 million USD from NV Energy. This California-based utility currently provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. Under the terms of the agreement, Emera and APIF will jointly own and operate these assets through a newly formed utility, California Pacific Electric Company ("California Pacific"). Emera's 50% equity investment in the common shares of California Pacific will be approximately $27 million USD. This transaction is subject to approval by the California Public Utilities Commission. The regulatory review process is expected to conclude in 2010.

The purchase of the 8.5 million units of APIF will happen concurrently with the closing of the California Pacific transaction and combined, these transactions are expected to add approximately $6 million CAD to Emera's annual consolidated net earnings. Emera will finance these acquisitions with existing credit facilities.

The subscription receipts have been accounted for as an "Available-for-sale investment". The receipts are recorded at cost as they do not have a quoted market price in an active market. The promissory note is recorded in "Short-term debt" and measured at its amortized cost using the effective interest method. The carrying value of the promissory note approximates its fair value given its short-term nature.

If this transaction does not result in an exchange of subscription receipts for common units of APIF, Emera and APIF will have no further rights or obligations under the Subscription and Unitholder Agreement. Emera would return all subscription receipts to APIF for cancellation and APIF would return Emera's promissory note for cancellation.

At the July 27, 2009, APIF unitholders' meeting, an extraordinary resolution was passed to approve an amendment to APIF's declaration of trust to facilitate the proposed trust unit for share exchange previously announced on June 12, 2009. Emera's April 2009 agreement with APIF contemplates the prospect of such an exchange and provides Emera with rights which allow it to maintain its percentage ownership of APIF at the date of its agreement with APIF in April 2009.

2009 Rate Decision

In September 2008, NSPI reached a settlement agreement with stakeholders on its 2009 rate application. The UARB approved that settlement agreement in November 2008 which included an average rate increase of 9.4% for most customer segments effective January 1, 2009. The settlement agreement included a Fuel Adjustment Mechanism ("FAM"), also effective January 1, 2009. The first rate adjustment under the FAM, effective, on January 1, 2010, was approved by the UARB on December 9, 2009. The UARB oversees the FAM, including review of fuel costs, contracts and transactions. With the implementation of the FAM, NSPI's regulated ROE range was established as 9.1% to 9.6% with 9.35% used to set rates.

Appointments

On May 6, 2009, John McLennan was named Chairman of Emera Inc.'s Board of Directors replacing Derek Oland, who will continue as a Director on both the Emera and NSPI Boards until his retirement in 2010. George Caines was named Chairman of NSPI's Board of Directors on the same day, replacing Mr. McLennan.

On September 25, 2009, George Caines was appointed to Emera Inc.'s Board of Directors.

Significant Item

Bear Swamp Mark-to-Market Adjustment

As part of its long-term energy and capacity supply agreement with the Long Island Power Authority ("LIPA"), Bear Swamp has contracted with its joint venture partners to provide the power necessary to produce the energy requirements of the LIPA contract. One of the contracts between Bear Swamp and Emera's joint venture partner is marked-to-market through earnings, as it does not meet the stringent accounting requirements of hedge accounting. As at December 31, 2009, the fair value of the net derivative asset was $6.2 million (December 31, 2008 – $4.9 million), which is subject to market volatility of power prices, and will reverse over the life of the agreement as it is realized. The agreement expires in 2021.

The mark-to-market adjustments relating to this position were as follows:

millions of dollars (except earnings per common share)	Three months ended December 31		Year ended December 31		
	2009	2008	**2009**	2008	2007
Mark-to-market gain (loss)	**$5.5**	$(6.0)	**$1.2**	$(8.1)	$15.7
After-tax mark-to-market gain (loss)	**$3.2**	$(3.6)	**0.7**	$(4.8)	$9.4
Earnings per common share – basic	**$0.33**	$0.23	**$1.56**	$1.29	$1.36
Earnings per common share – basic, absent the after-tax mark-to-market adjustment	**$0.30**	$0.26	**$1.55**	$1.33	$1.28

Review of 2009

Emera Consolidated Statements of Earnings

millions of dollars (except earnings per common share)	Three months ended December 31		Year ended December 31		
	2009	2008	**2009**	2008	2007
Electric revenue	**$344.8**	$330.6	**$1,378.7**	$1,280.8	$1,269.5
Finance income from direct financing lease	**15.2**	-	**25.3**	-	-
Other revenue	**29.1**	6.7	**61.5**	51.1	70.0
	389.1	337.3	**1,465.5**	1,331.9	1,339.5
Fuel for generation and purchased power	**150.8**	154.0	**565.5**	525.1	494.5
Fuel adjustment	**(10.6)**	-	**8.5**	-	-
Operating, maintenance and general	**83.8**	71.0	**292.8**	266.8	264.8
Provincial, state, and municipal taxes	**13.1**	12.2	**51.5**	49.4	47.5
Depreciation and amortization	**42.2**	39.0	**164.9**	151.3	149.3
Regulatory amortization	**16.4**	9.5	**35.7**	28.5	31.4
	93.4	51.6	**346.6**	310.8	352.0
Equity earnings	**2.0**	6.1	**14.0**	15.2	12.8
Financing charges	**45.7**	24.8	**135.3**	123.2	133.2
	49.7	32.9	**225.3**	202.8	231.6
Income taxes	**12.4**	7.0	**48.9**	58.1	80.3
Net earnings	**37.3**	25.9	**176.4**	144.7	151.3
Non-controlling interest	**(0.2)**	0.6	**0.7**	0.6	-
Net earnings applicable to common shares	**$37.5**	$25.3	**$175.7**	$144.1	$151.3
Earnings per common share – basic	**$0.33**	$0.23	**$1.56**	$1.29	$1.36
Earnings per common share – diluted	**$0.33**	$0.22	**$1.52**	$1.26	$1.32

Emera Inc.'s consolidated net earnings increased $12.2 million to $37.5 million in Q4 2009 compared to $25.3 million for the same period in 2008. Emera's annual consolidated net earnings increased $31.6 million to $175.7 million in 2009 compared to $144.1 million in 2008, and were $151.3 million in 2007.

Highlights of the changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Consolidated net earnings – 2007		**$151.3**
NSPI – increased net earnings due to an electricity price increase on April 1, 2007, decreased financing charges and accelerated income tax deductions, partially offset by increased fuel expense		5.4
Bangor Hydro – decreased net earnings due mainly to the capitalization of costs associated with the Northeast Reliability Interconnect ("NRI") transmission line		(4.4)
Pipelines – increased net earnings due mainly to allowance for funds used during construction ("AFUDC") on construction of Brunswick Pipeline, partially offset by increased intercompany interest on short-term debt used to finance the construction of the pipeline		3.4
Other – decreased net earnings primarily related to the after-tax mark-to-market adjustment on the unfavorable commodity price position in Bear Swamp as discussed in Significant Item		(19.8)
Corporate costs and other – decreased depreciation expense		8.2
Consolidated net earnings – 2008	**$25.3**	**$144.1**
NSPI – increased electric margin	3.0	3.7
Bangor Hydro – increased net earnings due mainly to an increase in the transmission rate and a weaker average CAD	0.4	4.4
Pipelines – increased net earnings from Brunswick Pipeline due to AFUDC on construction of the pipeline in the first half of the year and financing income from commencement of pipeline operations offset by increased financing charges related to the financing of the pipeline	1.5	8.8
Other – increased net earnings primarily related to the after-tax mark-to-market adjustments on the favourable commodity price positions in Bear Swamp and Emera Energy	14.7	10.9
Corporate costs and other – for the quarter increased deferred compensation costs and decreased management fees. Year-to-date decrease due to increased income tax recovery and intercompany financing revenues	(7.4)	3.8
Consolidated net earnings – 2009	**$37.5**	**$175.7**

Q4 basic earnings per share were $0.33 in 2009 compared to $0.23 in 2008; and $1.56 for the full year 2009 compared to $1.29 in 2008 and $1.36 in 2007.

Consolidated Net Earnings History

millions of dollars	2009	2008	2007	2006	2005	2004
Net earnings applicable to common shares	$175.7	$144.1	$151.3	$125.8	$121.2	$129.8
Net earnings applicable to common shares, absent the Bear Swamp after-tax mark-to-market adjustment	$175.0	$148.9	$141.9	$125.8	$121.2	$129.8

Earnings per Share History

Dollars	2009	2008	2007	2006	2005	2004
Earnings per share	$1.56	$1.29	$1.36	$1.14	$1.11	$1.20
Earnings per share, absent the Bear Swamp after-tax mark-to-market adjustment	$1.55	$1.33	$1.28	$1.14	$1.11	$1.20

Consolidated Balance Sheets Highlights

Significant changes in the consolidated balance sheets between December 31, 2009 and December 31, 2008 include:

millions of dollars	Increase (Decrease)	Explanation
Assets		
Accounts receivable	**$28.0**	Increased accounts receivable due to contract receivable classified as current from long-term and rate increase effective January 1, 2009 in NSPI, partially offset by lower posted margin to counterparties, and lower commodity prices.
Inventory	**43.3**	Increased fuel inventory levels and commodity mix.
Derivatives in a valid hedging relationship (including long-term portion)	**(107.9)**	Unfavorable USD price positions and additional hedges in NSPI. The effective portion of the change is recognized in "Accumulated other comprehensive loss".
Held-for-trading derivatives (including long-term portion)	**(88.1)**	Unfavourable commodity price positions and recognition of derivatives in earnings. The portion related to regulatory liabilities is recognized in "Other liabilities".
Long-term receivable	**(56.4)**	Long-term receivable reclassified to accounts receivable.
Future income tax assets (including long-term portion)	**26.4**	Primarily an accounting standard change requiring rate-regulated operations to recognize future income tax assets and liabilities effective January 1, 2009.
Goodwill	**(14.4)**	The effect of a stronger CAD.
Investments subject to significant influence	**(99.2)**	Primarily a return of capital from M&NP and the effect of a stronger CAD, offset by equity earnings.
Available-for-sale investments	**31.1**	Mainly due to purchase of subscription receipts of APIF.
Net investment in direct financing lease	**476.9**	Commencement of direct financing lease of Brunswick Pipeline.
Property, plant & equipment and construction work in progress	**(220.5)**	Purchase of Bayside and net capital additions in excess of depreciation expense primarily in NSPI, offset by the reclassification of Brunswick Pipeline to "Net investment in direct financing lease".
Liabilities and Shareholders' Equity		
Preferred shares issued by subsidiary	**(125.0)**	Redemption of NSPI's Series C preferred shares.
Derivatives in a valid hedging relationship (including long-term portion)	**(83.1)**	Favourable commodity price positions, additional hedges and recognition of derivatives in earnings. The effective portion of the change is recognized in "Accumulated other comprehensive loss".
Held-for-trading derivatives (including long-term portion)	**(11.8)**	Favourable commodity price positions partially offset by unfavourable commodity price positions in Emera Energy. The portion related to regulatory liabilities is recognized in "Other assets".
Future income tax liabilities	**83.8**	Primarily an accounting standard change requiring rate-regulated operations to recognize future income tax assets and liabilities effective January 1, 2009. The portion expected to be recovered from customers in future rates is recognized in "Other assets".
Asset retirement obligations	**16.5**	Recognition of obligation related to Brunswick Pipeline and a new environmental regulation in NSPI.
Other liabilities	**(88.6)**	Decreased regulatory liability related to financial instruments.
Short-term debt and long-term debt (including current portion)	**281.1**	Primarily new borrowings to finance the redemption of NSPI's Series C preferred shares, capital spending in NSPI and Brunswick Pipeline along with the acquisition of Bayside.
Common shares	**15.3**	Shares issued under purchase plans and stock options exercised.
Accumulated other comprehensive loss	**(117.5)**	Primarily the unfavourable effect of the CAD on the company's investment in Bangor Hydro offset by the change in hedges.
Retained earnings	**59.3**	Net earnings in excess of dividends declared.

Consolidated Cash Flow Highlights

Significant changes in the consolidated cash flow statements between December 31, 2009 and December 31, 2008 include:

Three months ended December 31 millions of dollars	**2009**	2008	Explanation
Cash and cash equivalents, beginning of period	**$27.7**	$28.5	
Provided by (used in):			
Operating activities	94.7	(17.1)	In 2009, cash earnings and decreased non-cash working capital.
			In 2008, increased non-cash working capital partially offset by cash earnings.
Investing activities	(163.9)	(146.7)	In 2009, capital spending, including multi year projects in NSPI and the completion of Brunswick Pipeline.
			In 2008, capital spending, including Brunswick Pipeline and an additional investment in M&NP.
Financing activities	63.8	147.5	In 2009, increased debt levels, partially offset by dividends on common shares.
			In 2008, increased debt levels, partially offset by dividends on common shares.
Foreign currency impact on cash balances	(0.5)	-	
Cash and cash equivalents, end of year	**$21.8**	$12.2	

Year ended December 31 millions of dollars	**2009**	2008	Explanation
Cash and cash equivalents, beginning of period	**$12.2**	$26.4	
Provided by (used in):			
Operating activities	302.8	237.2	In 2009, cash earnings partially offset by increased non-cash working capital.
			In 2008, cash earnings partially offset by increased non-cash working capital.
Investing activities	(367.2)	(671.6)	In 2009, capital spending including multi year projects in NSPI, Brunswick Pipeline, and acquisition of Bayside, partially offset by a return of capital from M&NP.
			In 2008, capital spending in Brunswick Pipeline, NSPI and Bangor Hydro, and acquisitions of a 7.35% interest in Open Hydro and a 50% interest in ICD Utilities Limited.
Financing activities	77.9	420.0	In 2009, increased long-term debt partially offset by decreased short-term debt, dividends on common shares and redemption of NSPI's preferred shares.
			In 2008, increased debt levels partially offset by dividends on common shares and decreased accounts receivable securitized.
Foreign currency impact on cash balances	(3.9)	0.2	
Cash and cash equivalents, end of year	**$21.8**	$12.2	

Outstanding Share Data

Issued and Outstanding:	Millions of Shares	Common Share Capital millions of dollars
December 31, 2007	111.47	$1,066.2
Issued for cash under purchase plans	0.39	8.0
Options exercised under senior management share option plan	0.35	6.4
Share-based compensation	-	0.8
December 31, 2008	112.21	$1,081.4
Issued for cash under purchase plans	0.45	8.7
Options exercised under senior management share option plan	0.32	5.8
Share-based compensation	-	0.8
December 31, 2009	112.98	$1,096.7

As at January 29, 2010, the number of issued and outstanding common shares was 113.03 million.

NOVA SCOTIA POWER INC.

Overview

NSPI, created following the privatization in 1992 of the crown corporation Nova Scotia Power Corporation, is a fully-integrated regulated electric utility and the primary electricity supplier in Nova Scotia with $3.5 billion of assets and provides electricity generation transmission and distribution services to approximately 486,000 customers in the province. The company owns 2,293 MW of generating capacity. Approximately 53% is coal-fired; natural gas and/or oil together comprise another 29% of capacity; and hydro and wind production provide 18%. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP"). These IPP's own 137 MW of wind and biomass fueled generation capacity. A further 212 MW of renewable capacity is being built directly or purchased under long term contract by NSPI, of which 163 MW are expected to be in service by the end of 2010. NSPI also owns approximately 5,000 kilometers of transmission facilities, and 27,000 kilometers of distribution facilities. The company has a workforce of approximately 1,900 people.

NSPI is a public utility as defined in the Public Utilities Act (Nova Scotia) ("Act") and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. The company is not subject to a general annual rate review process, but rather participates in hearings from time to time at the company's or the regulator'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 regulated ROE range for 2009 was 9.1% to 9.6%, on a common equity component of 45% of total capitalization.

Review of 2009

NSPI Net Earnings millions of dollars (except earnings per common share)	Three months ended December 31		Year ended December 31		
	2009	2008	**2009**	2008	2007
Electric revenue	**$302.9**	$280.7	**$1,188.1**	$1,111.1	$1,102.0
Fuel for generation and purchased power	**138.5**	139.5	**500.7**	471.4	433.7
Fuel adjustment	**(10.6)**	-	**8.5**	-	-
Operating, maintenance and general	**58.4**	52.3	**215.1**	203.7	206.0
Provincial grants and taxes	**10.0**	10.3	**40.5**	41.2	40.4
Depreciation and amortization	**36.8**	33.8	**143.9**	133.6	131.1
Regulatory amortization	**14.7**	6.4	**27.2**	17.7	17.2
Other revenue	**(4.0)**	(3.5)	**(14.0)**	(15.5)	(11.7)
	59.1	41.9	**266.2**	259.0	285.3
Financing charges	**33.3**	20.3	**114.7**	106.8	123.0
Earnings before income taxes	**25.8**	21.6	**151.5**	152.2	162.3
Income taxes	**8.4**	7.2	**42.2**	46.6	62.1
Contribution to consolidated net earnings	**$17.4**	$14.4	**$109.3**	$105.6	$100.2
Contribution to consolidated earnings per common share	**$0.15**	$0.12	**$0.97**	$0.94	$0.90

NSPI's contribution to consolidated net earnings increased $3.0 million to $17.4 million in Q4 2009, compared to $14.4 million in Q4 2008. Annual contribution to consolidated net earnings increased $3.7 million to $109.3 million in 2009 compared to $105.6 million in 2008, and was $100.2 million in 2007.

Highlights of the contribution to consolidated net earnings changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net earnings – 2007		**$100.2**
Increased electric revenue due to an electricity price increase on April 1, 2007		9.1
Increased fuel for generation and purchased power due to increased coal prices, changes in generation mix and increased coal plant maintenance		(37.7)
Decreased financing charges due to foreign exchange gains on USD denominated monetary net assets compared to foreign exchange losses; and lower interest costs		16.2
Decreased income taxes due to lower taxable income, accelerated deductions for capital items and a lower statutory rate		15.5
Other		2.3
Contribution to consolidated net earnings – 2008	**$14.4**	**$105.6**
Increased electric revenue due to an electricity price increase on January 1, 2009 partially offset by decreased industrial sales in the year	22.2	77.0
Decreased (increased) fuel for generation and purchased power	1.0	(29.3)
Fuel adjustment related to implementation of FAM	10.6	(8.5)
Increased operating, maintenance and general primarily due to increased storm and reliability costs as well as customer service initiatives partially offset by decreased pension expense	(6.1)	(11.4)
Increased depreciation and amortization primarily due to increased depreciation rates in 2009 as part of the phase-in of year-three rates as approved by the UARB	(3.0)	(10.3)
Increased financing charges	(13.0)	(7.9)
Increased regulatory amortization due to additional amortization of pre-2003 income tax regulatory asset	(8.3)	(9.5)
Increased income taxes in the quarter due to higher taxable income partially offset by lower statutory rate; year-to-date decrease due to decreased taxable income and lower statutory rate, partially offset by recovery of income taxes in 2008 relating to a prior year	(1.2)	4.4
Other	0.8	(0.8)
Contribution to consolidated net earnings – 2009	**$17.4**	**$109.3**

Electric Revenue

Q4 Electric Sales Volumes
Gigawatt hours ("GWh")

	2009	2008	2007
Residential	**1,091**	1,093	1,064
Commercial	**772**	770	793
Industrial	**998**	987	1,046
Other	**81**	84	99
Total	**2,942**	2,934	3,002

Year-to-Date ("YTD") Electric Sales Volumes
GWh

	2009	2008	2007
Residential	**4,228**	4,179	4,145
Commercial	**3,107**	3,115	3,161
Industrial	**3,642**	4,144	4,191
Other	**328**	334	365
Total	**11,305**	11,772	11,862

Q4 Electric Revenues
millions of dollars

	2009	2008	2007
Residential	**$140.4**	$129.1	$125.7
Commercial	**84.2**	76.9	78.5
Industrial	**67.3**	64.2	67.5
Other	**11.0**	10.5	11.4
Total	**$302.9**	$280.7	$283.1

YTD Electric Revenues
millions of dollars

	2009	2008	2007
Residential	**$547.3**	$496.3	$485.6
Commercial	**333.9**	305.2	307.6
Industrial	**263.8**	268.1	266.6
Other	**43.1**	41.5	42.2
Total	**$1,188.1**	$1,111.1	$1,102.0

Q4 Average Electric Revenue / MWh

	2009	2008	2007
Dollars per MWh	**$103**	$96	$94

YTD Average Electric Revenue / MWh

	2009	2008	2007
Dollars per MWh	**$105**	$94	$93

The increase in average revenue per MWh in 2009 compared to 2008 reflects the January 1, 2009, 9.4% rate increase noted above and a change in sales mix.

The average revenue per MWh is higher in 2008 compared to 2007 reflecting the April 1, 2007, 3.8% rate increase noted above.

Electric sales volume is primarily driven by general economic conditions, population and weather. Electricity pricing in Nova Scotia is regulated and changes when new regulatory decisions are implemented. The exceptions are annually adjusted rates, subscribed to by certain larger industrial customers, and export sales, priced at market, which in recent years comprised less than 2% of NSPI sales volume. 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 consists of export sales, sales to municipal electric utilities and revenues from street lighting.

For the three months ended December 31, 2009, electric revenue increased $22.2 million to $302.9 million, compared to $280.7 million in Q4 2008. For the year ended December 31, 2009, electric revenue increased $77.0 million to $1,188.1 million compared to $1,111.1 million in 2008 and $1,102.0 million in 2007. Highlights of the changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Electric revenue – 2007		**$1,102.0**
Increased electricity pricing effective April 1, 2007		12.3
Net change in residential and commercial sales volumes		(0.5)
Decreased industrial sales volumes to several large industrial customers		(1.5)
Decreased export sales		(1.2)
Electric revenue – 2008	**$280.7**	**$1,111.1**
Increased electricity pricing effective January 1, 2009	20.4	102.1
Net change in residential and commercial sales volumes	(0.2)	4.2
Increased (decreased) industrial sales to several large industrial customers	2.1	(28.3)
Decreased export sales	(0.1)	(1.0)
Electric revenue – 2009	**$302.9**	**$1,188.1**

Fuel for Generation and Purchased Power

Capacity

To ensure reliability of service, NSPI maintains a generating capacity greater than firm peak demand. The total company-owned generation capacity is 2,293 MW, which is supplemented by 137 MW contracted with independent power producers. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area, and the Northeast Power Coordinating Council.

Management of capacity and capacity utilization is a critical element of operating efficiency. The provision of sufficient generating capacity to meet peak demand inevitably results in excess capacity in non-peak periods, which allows for annual maintenance programs to be carried out without compromising reserve capacity requirements. NSPI's daily load is generally highest in the early evening and its seasonal load is highest through the winter months. Maximizing capacity utilization can defer investment in additional generation capacity. Maximizing capacity utilization primarily depends on:

- Ensuring generating plants are consistently available to service demand – NSPI conducts ongoing planned maintenance programs and has sustained high availability over the past several years. NSPI maintains low forced and unplanned outage rates compared to North American averages.

- Moving demand from peak to non-peak periods – NSPI encourages customers to move electricity demand from high cost to lower cost periods by offering customers various pricing alternatives. NSPI also controls over 400 MW of interruptible electric load; including over 250 MW of energy supplied under real time rates.

- Export sales – Increasing export sales when margins are satisfactory allows energy from excess capacity to be sold when not required in the province. NSPI operates a 24-hour marketing desk to optimize commercial opportunities such as export sales.

NSPI Thermal Capacity Utilization

2009	2008	2007	2006	2005
70%	75%	79%	71%	78%

NSPI Thermal Capacity Availability

2009	2008	2007	2006	2005
82%	88%	91%	90%	90%

NSPI's thermal capacity utilization was 70% in 2009 compared to 75% in 2008. This change was due to decreased domestic load largely resulting from decreased sales to industrial and commercial customers as a result of the global economic recession.

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 2009, thermal plant availability was 82%. The decrease in availability from 2008 reflects extended maintenance outages. Sustained high availability and low forced outage rates on low cost facilities are good indicators of sound maintenance and investment practices.

Fuel Expense

Q4 Production Volumes
GWh

	2009	2008	2007
Coal & petcoke	**2,069**	2,177	2,519
Natural gas	**534**	249	333
Oil & diesel	**16**	218	45
Renewable	**281**	257	218
Purchased power	**335**	296	189
Total	**3,235**	3,197	3,304

Purchased power includes 51 GWh of renewables in 2009 (2008 – 44 GWh; 2007 – 49 GWh).

YTD Production Volumes
GWh

	2009	2008	2007
Coal & petcoke	**8,177**	9,009	9,561
Natural gas	**1,612**	1,258	1,057
Oil & diesel	**307**	339	515
Renewable	**1,065**	1,068	911
Purchased power	**931**	889	654
Total	**12,092**	12,563	12,698

Purchased power includes 149 GWh of renewables in 2009 (2008 – 148 GWh; 2007 – 161 GWh).

Q4 Average Unit Fuel Costs

	2009	2008	2007
Dollars per MWh	**$43**	$44	$33

YTD Average Unit Fuel Costs

	2009	2008	2007
Dollars per MWh	**$41**	$38	$34

Solid fuel is NSPI's dominant fuel source, supplying approximately 68% of the company's annual energy. Historically, solid fuels have had the lowest per unit fuel cost, after hydro and NSPI-owned wind production, which have no fuel cost component. Oil, natural gas, and purchased power are next, depending on the relative pricing of each. Economic dispatch of the generating fleet brings the lowest cost options on stream first, with the result that the incremental cost of production increases as sales volume increases.

The average unit fuel costs increased in 2009 compared to 2008 mainly as a result of higher priced commodity contracts for coal and natural gas.

The average unit fuel costs increased in 2008 compared to 2007 mainly due to the decreased value of the natural gas supply contract as reflected in the long-term receivable, and change in generation mix due to lower coal production due to an increase in coal plant maintenance. Increased coal prices were partially offset by the economic use of natural gas and favourable hedge positions as a result of this fuel switch.

A substantial amount of NSPI's fuel supply comes from international suppliers, and is subject to commodity price and foreign exchange risk. The company manages exposure to commodity price risk utilizing a portfolio strategy, combining physical fixed-price fuel contracts and financial instruments providing fixed or maximum prices. Foreign exchange risk is managed through forward and option contracts. Further details on the company's fuel cost risk management strategies are included in the Business Risks section. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms.

For the three months ended December 31, 2009, fuel for generation and purchased power decreased $1.0 million to $138.5 million, compared to $139.5 million in Q4 2008. For the year ended December 31, 2009, fuel for generation and purchased power increased $29.3 million to $500.7 million compared to $471.4 million in 2008 and $433.7 million in 2007. Highlights of the changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Fuel for generation and purchased power – 2007		**$433.7**
Increased coal prices partially offset by the economic use of natural gas and favourable hedge positions as a result of this fuel switch		18.3
Decreased sales volume		(9.9)
Decreased net proceeds from the resale of natural gas due to the economic decision to use natural gas in the production process		8.8
Increased hydro production		(11.9)
Changes in generation mix due to increased coal plant maintenance		30.7
Other		1.7
Fuel for generation and purchased power – 2008	**$139.5**	**$471.4**
Commodity price increases	14.5	36.2
(Increased) decreased proceeds from the resale of natural gas	(2.8)	10.3
Valuation of contract receivable (see discussion below)	(13.0)	4.5
Increased (decreased) sales volume	4.3	(22.2)
Mark-to-market on natural gas hedges not required in 2009 primarily due to decreased production volumes	(0.6)	(0.7)
Changes in generation mix and plant performance	(7.1)	(10.2)
(Increased) decreased hydro production	(0.6)	1.8
Primarily solid fuel handling costs previously included in "Operating, maintenance and general expenses"	5.0	10.7
Other	(0.7)	(1.1)
Fuel for generation and purchased power – 2009	**$138.5**	**$500.7**

The valuation of the contract receivable from a natural gas supplier requires NSPI to utilize a combination of historical and future natural gas prices. NSPI uses market-based forward indices when determining future prices. Future prices can change from period to period which will cause a corresponding change in the value of the contract receivable.

Fuel Adjustment

The UARB approved the implementation of a fuel adjustment mechanism in the company's 2009 General Rate Decision effective January 1, 2009. The FAM is subject to an incentive with NSPI retaining or absorbing 10% of the over or under-recovered amount less the difference between the incentive threshold and the base fuel cost to a maximum of $5 million.

For the year ended December 31, 2009, actual fuel costs were less than amounts recovered from customers. The difference has been recorded as an expense, and accrued to a FAM regulatory liability in "Other liabilities". As a result of the effective management of fuel on behalf of customers, NSPI earned a $5 million FAM incentive in 2009.

The Company has recognized a future income tax recovery related to the fuel adjustment based at its applicable statutory income tax rate.

As at December 31, 2009, NSPI's FAM regulatory liability was $9.9 million (2008 – nil), and the related future income tax asset was $3.4 million (2008 – nil). The FAM regulatory liability includes amounts recognized as a fuel adjustment and associated interest carrying costs included in "Financing charges". The fuel adjustment includes fuel-related foreign exchange gains and losses that are reported as part of "Financing charges".

In December 2009, as part of the FAM regulatory process, customer rates were set for 2010 based on the projected over-recovery of fuel costs in 2009. The customer "Actual Adjustment" ("AA") reflects a combination of actual and forecasted fuel costs and customer fuel recoveries for the period. The customer FAM AA rate decrease was set based on a projected over-recovery of fuel costs of $22.0 million (1.4%). The difference between the actual FAM AA of $9.9 million and the $22.0 million used to set 2010 rates will be recovered in 2011 as part of the FAM Balancing Adjustment ("BA") along with interest and any variances in 2010 sales volumes.

In the absence of UARB approval, the fuel adjustment would not have been recognized and earnings for the three months ended December 31, 2009 would be $10.2 million ($6.7 million after-tax) lower (2008-nil) and for the year ended December 31, 2009 would be $9.9 million ($6.5 million after-tax) higher (2008 – nil).

Operating, Maintenance and General

Operating, maintenance and general expenses have increased $6.1 million to $58.4 million in Q4 2009 compared to $52.3 million in Q4 2008 and increased $11.4 million to $215.1 million for the year ended December 31, 2009 compared to $203.7 million in 2008 primarily due to increased storm costs, system reliability spending and program costs associated with customer and new business initiatives. These cost increases were partially offset by lower pension expense.

Operating, maintenance and general expenses remained relatively unchanged for the year ended December 31, 2008 compared to 2007.

Provincial Grants and Taxes

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

Depreciation

Depreciation expense increased $3.0 million to $36.8 in Q4 2009 compared to $33.8 million in Q4 2008 and increased $10.3 million to $143.9 for the year ended December 31, 2009 compared to $133.6 million in 2008 primarily due to the inclusion of year-three depreciation rates commencing on January 1, 2009 as approved by the UARB in its November 5, 2008 decision.

For the year ended December 31, 2008, depreciation expense increased $2.5 million to $133.6 million compared to $131.1 million in 2007 due to plant additions.

Regulatory Amortization

Regulatory amortization increased $8.3 million to $14.7 million in Q4 2009 compared to $6.4 million in Q4 2008 and increased $9.5 million to $27.2 million for the year ended December 31, 2009 compared to $17.7 million in 2008 due primarily to amortization of the pre-2003 income tax regulatory asset resulting from the UARB's ROE decision in January 2010. This decision allows NSPI to recognize additional amortization amounts in current periods and to reduce amounts in future periods which provides flexibility relating to customer rate requirements.

For the year ended December 31, 2008, regulatory amortization increased $0.5 million to $17.7 million compared to $17.2 million in 2007 due to the amortization of the pre-2003 income tax regulatory asset partially offset by the completion of the Glace Bay generating station amortization in 2007.

Other Revenue

Other revenue, which consists of miscellaneous revenues and commercial settlements, has remained relatively unchanged for the year ended December 31, 2009 compared to 2008.

For the year ended December 31, 2008, other revenue increased $3.8 million to $15.5 million compared to $11.7 million in 2007 due to increased commercial settlements received and a reduction in the accounts receivable securitization program which resulted in lower fees.

Financing Charges

Financing charges increased $13.0 million to $33.3 million in Q4 2009 compared to $20.3 million in Q4 2008 and increased $7.9 million to $114.7 million for the year ended December 31, 2009 compared to $106.8 million in 2008 primarily due to lower foreign exchange gains in 2009 compared to 2008. In 2009, NSPI recorded income tax refund interest of $3 million which was received as a result of the company amending its 1999 to 2003 corporate income tax returns. This refund interest was recorded as a reduction of "Financing charges".

Financing charges decreased $16.2 million to $106.8 million for the year ended December 31, 2008 compared to $123.0 million in 2007 primarily due to foreign exchange gains in 2008 partially offset by income tax recovery interest in 2007. In Q4 2007, NSPI recorded income tax refund interest of $8.6 million, $1.8 million of which has been recorded as a reduction of “Other assets”. The remaining $6.8 million has been recorded as a reduction of “Financing charges”.

Income Taxes

NSPI uses the future income tax method of accounting for income taxes. In accordance with NSPI's rate-regulated accounting policy as approved by the UARB, NSPI defers any future income taxes to a regulatory asset or liability where the future income taxes are expected to be included in future rates.

In 2009, NSPI was subject to provincial capital tax (0.175%), corporate income tax (35%) and Part VI.1 tax relating to preferred dividends (40%). NSPI also receives a reduction in its corporate income tax otherwise payable related to the Part VI.1 tax deduction (42% of preferred dividends).

During 2008, NSPI accelerated the deduction of capitalized expenses pertaining to the 2007 tax year. As a result, in 2008, NSPI recorded an income tax recovery of $6.5 million. NSPI continues to use this methodology.

BANGOR HYDRO

All amounts in the Bangor Hydro section are reported in USD unless otherwise stated.

Overview

Bangor Hydro's core business is the transmission and distribution of electricity. Bangor Hydro is the second largest electric utility in Maine. Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the commodity that is delivered through the Bangor Hydro T&D network. Bangor Hydro owns and operates approximately 1,300 kilometers of transmission facilities, and 6,800 kilometers of distribution facilities. Bangor Hydro invested approximately $141 million in the Northeast Reliability Interconnect ("NRI"), an international electricity transmission line connecting New Brunswick to Maine, which went in service in 2007, and currently has approximately $130 million of additional transmission development in progress. Bangor Hydro's workforce is approximately 270 people.

In addition to T&D assets, Bangor Hydro has net "regulatory" assets (stranded costs), which arose through the restructuring of the electricity industry in the state in the late 1990s, and as a result of rate and accounting orders issued by its regulator. 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. Unlike T&D operational assets, which are generally sustained with new investment, the regulatory asset pool diminishes over time, as elements are amortized through charges to earnings, and recovered through rates. These regulatory assets total approximately $45.0 million at December 31, 2009 (2008 – $55.2 million), or 7% of Bangor Hydro's net asset base (2008 – 8%).

Approximately 47% of Bangor Hydro's electric rate represents distribution service, 40% is associated with transmission service, and 13% relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings. Bangor Hydro's distribution operations and stranded costs are regulated by the Maine Public Utilities Commission ("MPUC"). The transmission operations are regulated by the Federal Energy Regulatory Commission ("FERC").

Bangor Hydro operates under a traditional cost-of-service regulatory structure. In December 2007, the MPUC approved an increase of approximately 2% in distribution rates effective January 1, 2008. The allowed ROE used in setting these distribution rates was 10.2%, with a common equity component of 50%.

Transmission rates are set by the FERC annually on June 1, based upon a formula that utilizes prior year actual transmission investments and expenses, adjusted for current year forecasted transmission investments and expenses. In 2009, Bangor Hydro implemented this forward-looking rate formula for its local transmission investments, replacing an approach which had resulted in a lag in the recovery of transmission investments and costs. The allowed ROE for transmission operations ranges from 11.14% for low voltage local transmission up to 12.64% for high voltage regionally funded transmission developed as a result of the regional system plan.

In December 2007, the MPUC issued an order approving an approximate 39% reduction in stranded cost rates for the three-year period beginning March 1, 2008. The reduced stranded cost revenues are offset for the most part by decreased regulatory amortizations, decreased purchased power costs, and increased resale of purchased power. The allowed ROE used in setting the new stranded cost rates is 8.5%. Prior to that, stranded cost rates provided for an allowed ROE of 10%. On June 1, 2009, Bangor Hydro further reduced its stranded cost rates for a one-year period by approximately 15% to reflect an overcollection of certain stranded cost revenues and expenses under a full reconciliation rate mechanism.

Appointments

Effective January 1, 2010, Gerard Chasse was appointed President and Chief Operating Officer ("COO") of Bangor Hydro. Robert Hanf, former President and COO, now serves as Chief Executive Officer.

Review of 2009

Bangor Hydro Net Earnings millions of USD (except earnings per common share)	Three months ended December 31		Year ended December 31		
	2009	2008	**2009**	2008	2007
T&D electric revenues	**$25.9**	$25.9	**$102.8**	$97.6	$101.7
Resale of purchased power	**4.9**	5.4	**18.9**	20.4	14.6
Transmission pool revenue	**3.0**	3.2	**14.0**	16.5	12.7
Total revenue	**33.8**	34.5	**135.7**	134.5	129.0
Fuel for generation and purchased power	**7.6**	8.1	**29.4**	32.2	31.9
Operating, maintenance and general	**7.4**	7.8	**30.9**	28.8	26.3
Property taxes	**1.7**	1.3	**6.3**	5.4	4.8
Depreciation	**4.0**	3.9	**16.0**	15.3	13.0
Regulatory amortization	**1.6**	2.6	**7.4**	10.1	13.2
Other	**(0.5)**	(0.7)	**(2.6)**	(3.8)	(2.1)
	12.0	11.5	**48.3**	46.5	41.9
Financing charges	**2.2**	2.6	**10.4**	11.1	3.2
Earnings before income taxes	**9.8**	8.9	**37.9**	35.4	38.7
Income taxes	**3.3**	3.6	**13.5**	13.9	13.0
Contribution to consolidated net earnings – USD	**$6.5**	$5.3	**$24.4**	$21.5	$25.7
Contribution to consolidated net earnings – CAD	**$7.0**	$6.6	**$27.5**	$23.1	$27.5
Contribution to consolidated earnings per common share – CAD	**$0.06**	$0.07	**$0.24**	$0.21	$0.25
Net earnings weighted average foreign exchange rate – CAD /USD	**$1.08**	$1.23	**$1.13**	$1.07	$1.07

Bangor Hydro's contribution to consolidated net earnings increased by $1.2 million to $6.5 million in Q4 2009 compared to $5.3 million in Q4 2008. Annual contribution to consolidated net earnings increased by $2.9 million to $24.4 million compared to $21.5 million in 2008 and was $25.7 million in 2007. Highlights of the earnings changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net earnings – 2007		**$25.7**
Increased net transmission pool revenue offset by a decrease in miscellaneous transmission charges		5.0
Decreased overheads and AFUDC capitalized in 2008 primarily as a result of completing the NRI transmission line in Q4 2007		(10.0)
Increased interest expense and depreciation primarily related to the NRI transmission line		(3.0)
Other		3.8
Contribution to consolidated net earnings – 2008	**$5.3**	**$21.5**
Increased T&D electric revenues due to transmission rate increases and additional transmission revenues from wind generation	-	5.2
Lower net transmission pool revenue due to increased regional charges	(0.2)	(2.5)
Decreased (increased) operating, maintenance and general expenses due to increased storm, regulatory and labour costs	0.4	(2.1)
Decreased financing charges primarily due to lower short-term interest rates	0.4	0.7
Other	0.6	1.6
Contribution to consolidated net earnings – 2009	**$6.5**	**$24.4**

Bangor Hydro's increased contribution to consolidated net earnings in CAD in Q4 2009 compared to Q4 2008 was partially offset by the $1.0 million impact of the stronger Canadian dollar in the quarter. Bangor

Hydro's increased contribution to consolidated net earnings in CAD in 2009 compared to 2008 was partially offset by the $1.5 million impact of the weaker Canadian dollar on average during the year.

Electric Revenue

Q4 Electric Sales Volumes
GWh

	2009	2008	2007
Residential	**154**	155	157
Commercial	**145**	145	149
Industrial	**78**	90	102
Other	**3**	2	3
Total	**380**	392	411

YTD Electric Sales Volumes
GWh

	2009	2008	2007
Residential	**591**	591	594
Commercial	**588**	604	606
Industrial	**342**	350	379
Other	**12**	10	12
Total	**1,533**	1,555	1,591

Q4 Electric Revenues
millions of dollars

	2009	2008	2007
Residential	**$12.6**	$12.8	$13.0
Commercial	**9.1**	8.7	9.0
Industrial	**2.4**	3.0	2.7
Other	**1.8**	1.4	1.2
Total	**$25.9**	$25.9	$25.9

YTD Electric Revenues
millions of dollars

	2009	2008	2007
Residential	**$48.3**	$47.6	$49.6
Commercial	**35.9**	34.5	36.5
Industrial	**10.2**	10.0	11.1
Other	**8.4**	5.5	4.5
Total	**$102.8**	$97.6	$101.7

Q4 Electric Average Revenue / MWh

	2009	2008	2007
Dollars per MWh	**$68**	$66	$63

YTD Electric Average Revenue / MWh

	2009	2008	2007
Dollars per MWh	**$67**	$63	$64

The changes in average revenue per MWh in 2009 compared to 2008 reflect the increase in transmission rates on July 1, 2008 and June 1, 2009, as well as reductions in stranded cost rates on March 1, 2008 and June 1, 2009.

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.

Electric revenues were flat at $25.9 million in Q4 2009 compared to Q4 2008. For the year ended December 31, 2009, electric revenues increased $5.2 million to $102.8 million compared to $97.6 million for 2008 due to increased transmission rates, including the impact of moving to a forward-looking rate formula, offset partially by a reduction in stranded cost rates. For the year ended December 31, 2008, electric revenues decreased $4.1 million to $97.6 million compared to $101.7 million for 2007 due to decreased sales volume and decreased stranded cost rates.

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

Bangor Hydro has several above-market purchase power contracts pre-dating the Maine market restructuring. Power purchased under these arrangements is resold to a third party at market rates as determined through a bid process administered and approved by the MPUC. The difference between the cost of the power purchased under these arrangements and the revenue collected from the third party is recovered through stranded cost rates.

Transmission Pool Revenue

Bangor Hydro recovers the cost of its regionally funded transmission infrastructure investment, through transmission pool revenue based on a regional formula that is updated on June 1st of each year. Transmission pool revenue, less transmission infrastructure investment charges, is recovered from the New England Power Pool ("NEPOOL").

Transmission pool revenue decreased by $0.2 million in Q4 2009 to $3.0 million compared to $3.2 million in Q4 2008 and decreased $2.5 million to $14.0 million for the year ended December 31, 2009, compared to $16.5 million for 2008 due to greater regional charges related to increased regional transmission investments.

Depreciation

Depreciation expense increased $0.1 million to $4.0 million in Q4 2009 compared to $3.9 million in Q4 2008; and increased $0.7 million to $16.0 million in 2009 compared to $15.3 million in 2008 primarily due to increased transmission investments.

Financing Charges

Financing charges decreased $0.4 million to $2.2 million in Q4 2009 compared to $2.6 million in Q4 2008 and decreased $0.7 million to $10.4 million for the year ended December 31, 2009, compared to $11.1 million in 2008 primarily due to lower short-term interest rates in 2009.

Financing charges increased $7.9 million to $11.1 million in 2008 compared to $3.2 million in 2007 primarily due to increased debt used to finance the NRI transmission line and decreased AFUDC capitalized on the NRI transmission line which went into service in Q4 2007.

Income Taxes

Bangor Hydro uses the future income tax method of accounting for income taxes.

Bangor Hydro is subject to corporate income tax at the statutory rate of 40.8% (combined federal and state income tax rate). Bangor Hydro’s effective income tax rate was reduced in 2009 as compared to 2008 primarily due to a change in tax accounting associated with the capitalization of certain repair costs.

PIPELINES

Overview

Pipelines is composed of the company's investments in a wholly-owned subsidiary, Brunswick Pipeline, along with the company's 12.9% interest in Maritimes & Northeast Pipeline ("M&NP").

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Canaport™ LNG import terminal near Saint John, New Brunswick, to markets in Canada and the northeastern United States. The pipeline, which received National Energy Board approval for shipping gas in January 2009, and went into service on July 16, 2009, transports re-gasified LNG for Repsol Energy Canada under a 25 year firm service agreement. The National Energy Board, which regulates Brunswick Pipeline, has classified it as a Group 2 pipeline.

The company acquired a 12.9% interest in M&NP in 1999. M&NP is a $2 billion, 1,400-kilometre pipeline which transports natural gas from offshore Nova Scotia to markets in Maritime Canada and the northeastern United States.

Review of 2009

Pipelines Net Earnings millions of dollars	Three months ended December 31		Year ended December 31		
	2009	2008	**2009**	2008	2007
Brunswick Pipeline					
Finance income from direct financing lease	**$15.2**	-	**$25.3**	-	-
AFUDC	**-**	$7.0	**18.8**	$15.6	-
Financing charges	**8.8**	4.7	**30.1**	12.4	$(1.4)
Brunswick Pipeline net earnings	**6.4**	2.3	**14.0**	3.2	1.4
M&NP equity earnings	**2.0**	4.6	**10.2**	12.2	10.6
Contribution to consolidated net earnings	**$8.4**	$6.9	**$24.2**	$15.4	$12.0
Contribution to consolidated earnings per common share	**$0.07**	$0.06	**$0.22**	$0.14	$0.11

The total contribution of Pipelines to consolidated net earnings increased $1.5 million to $8.4 million in Q4 2009 compared to $6.9 million in Q4 2008. Annual contribution to consolidated net earnings increased $8.8 million to $24.2 million in 2009 compared to $15.4 million in 2008 and $12.0 million in 2007.

Highlights of the earnings changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net earnings – 2007		**$12.0**
Brunswick Pipeline – increase due to AFUDC on construction of the pipeline		15.6
Brunswick Pipeline – increase in financing charges due to increased short-term debt used to finance the construction of the pipeline and foreign exchange losses		(13.8)
M&NP equity earnings		1.6
Contribution to consolidated net earnings – 2008	**$6.9**	**$15.4**
Brunswick Pipeline – financing income from direct financing lease	15.2	25.3
Brunswick Pipeline – there was no AFUDC in the quarter as it was operational in 2009; increased AFUDC on construction of the pipeline during the first half of the year prior to the pipeline commencing service	(7.0)	3.2
Brunswick Pipeline – increase in financing charges due to increased construction spending	(4.1)	(17.7)
M&NP equity earnings	(2.6)	(2.0)
Contribution to consolidated net earnings – 2009	**$8.4**	**$24.2**

Brunswick Pipeline

Brunswick Pipeline meets the definition of a direct financing capital lease for accounting purposes. The net investment in direct financing lease is the sum of the expected toll revenues, less the residual value and estimated operating costs on the pipeline shown net of unearned finance income. The unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.

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.

Maritimes & Northeast Pipeline

Equity earnings for M&NP decreased by $2.6 million to $2.0 million in Q4 2009 compared to $4.6 million in Q4 2008 due to increased financing charges on the United States (“US”) portion of the pipeline as a result of debt recapitalization and the recognition of a portion of the EnCana Marketing (USA) Inc. (“Encana”) settlement in Q4 2008, combined with a stronger Canadian dollar in Q4 2009 compared to Q4 2008.

For the year ended December 31, 2009 M&NP equity earnings decreased $2.0 million to $10.2 million compared to $12.2 million in 2008 due to increased financing charges on the US portion of the pipeline as a result of the debt recapitalization.

In late 2007, M&NP and EnCana entered into an agreement whereby M&NP would expand its facilities on the US portion of the pipeline and M&NP would provide firm transport service to EnCana. In 2008, EnCana terminated the agreement and a settlement agreement was reached in Q4 2008. A portion of the settlement proceeds was recognized in Q4 2008 with the remaining portion recognized in Q1 2009.

During Q3 2008, M&NP, using equity contributions from its partners, repaid its outstanding debt related to the US portion of the pipeline. Emera’s portion of these equity contributions was $46.5 million USD ($47 million CAD).

In May 2009, M&NP recapitalized the US portion of the pipeline by issuing a $500 million USD long-term debt. The net proceeds of the debt issuance were distributed to the partners. Emera’s portion of the net proceeds was $64.2 million USD ($73.8 million CAD), and was recorded as a return of capital from M&NP.

Income Taxes

Brunswick Pipeline uses the future income tax method of accounting for income taxes. In accordance with rate-regulated accounting, Brunswick Pipeline defers any future income taxes to a regulatory asset or liability where the future income taxes are expected to be included in the future tolls. M&NP equity earnings are recorded net of tax.

OTHER, INCLUDING CORPORATE COSTS

All activities of Emera other than its two wholly-owned regulated electric utilities and its pipelines are incorporated into Other, including:

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, a 260-MW gas-fired merchant electricity generating facility in Saint John, New Brunswick; and Bear Swamp, a 50/50 joint venture, in a 600-MW pumped storage hydro-electric facility in northern Massachusetts.

Caribbean Investments include Lucelec, a 19% interest in a vertically-integrated electric utility on the Caribbean island of St. Lucia, and GBPC, a 25% interest in a vertically-integrated electric utility on Grand Bahama Island.

Corporate and other costs pertain to certain corporate-wide functions such as executive management, strategic planning, treasury services, financial reporting, tax planning, business development, corporate governance, and financing costs and income taxes associated with the corporation's business outside of NSPI, Bangor Hydro and Brunswick Pipeline.

Review of 2009

Other Net Earnings

Emera Energy operations are reported on a net earnings basis. Caribbean operations which include Lucelec and GBPC, are reported on an equity earnings basis.

Other Net Earnings millions of dollars (except earnings per common share)	Three months ended December 31		Year ended December 31		
	2009	2008	**2009**	2008	2007
Emera Energy	**$14.8**	$(1.8)	**$20.7**	$15.0	$36.8
Caribbean	**-**	1.5	**3.6**	3.0	2.2
	14.8	(0.3)	**24.3**	18.0	39.0
Financing charges	**0.7**	4.2	**4.9**	10.0	4.5
Income taxes	**5.9**	1.2	**6.2**	5.8	13.1
	8.2	(5.7)	**13.2**	2.2	21.4
Non-controlling interest	**0.2**	(0.6)	**(0.7)**	(0.6)	-
Contribution to consolidated net earnings	**$8.4**	$(6.3)	**$12.5**	$1.6	$21.4
Contribution to consolidated net earnings per common share	**$0.07**	$(0.06)	**$0.11**	$0.01	$0.19
Contribution to consolidated net earnings, absent the Bear Swamp after-tax mark-to-market adjustment	**$5.2**	$(2.7)	**$11.8**	$6.4	$12.0
Contribution to consolidated net earnings per common share, absent the Bear Swamp after-tax mark-to-market adjustment	**$0.04**	$(0.03)	**$0.10**	$0.06	$0.11

The total contribution of Other to consolidated net earnings increased $14.7 million to $8.4 million in Q4 2009 compared to $(6.3) million in Q4 2008. Annual contribution to consolidated net earnings increased $10.9 million to $12.5 million in 2009 compared to $1.6 million in 2008, and was $21.4 million in 2007. Highlights of the earnings changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net earnings – 2007		**$21.4**
Emera Energy - Bear Swamp – operational – increase in energy and forward reserve sales		6.9
Emera Energy - Bear Swamp – mark-to-market – decrease due to an unfavourable commodity price position		(23.8)
Emera Energy - Emera Energy Services – decrease primarily due to reduced activity		(4.9)
Caribbean - Equity earnings from GBPC, purchased in Q3 2008		0.8
Financing charges increased due to foreign exchange losses		(5.5)
Income taxes decrease due to reduced earnings		7.3
Non-controlling interest in GBPC		(0.6)
Contribution to consolidated net earnings – 2008	**$(6.3)**	**$1.6**
Emera Energy - Bear Swamp – operational – due primarily to a write-off of a development project and increased power costs related to supplying the LIPA contract	0.1	(2.8)
Emera Energy - Bear Swamp – mark-to-market – increase due to favourable changes in the commodity price position	11.5	9.3
Emera Energy - Emera Energy Services – increase in the quarter primarily due to acquisition of Bayside including mark-to-market gains on gas supply contracts offset by reduced transportation mitigation opportunities. Decreased YTD as a result of reduced transportation mitigation opportunities	5.0	(0.8)
Caribbean - Equity earnings	(1.5)	0.6
Financing charges decreased primarily due to lower interest rates in Bear Swamp and decreased average external debt	3.5	5.1
Income taxes increase due to higher earnings	(4.7)	(0.4)
Non-controlling interest in GBPC	0.8	(0.1)
Contribution to consolidated net earnings – 2009	**$8.4**	**$12.5**

Emera Energy

Bear Swamp

Bear Swamp's earnings before interest and other income taxes ("EBIT") represent Emera's 50% investment in the Bear Swamp joint venture.

Bear Swamp – Operational

Bear Swamp EBIT – operational increased $0.1 million to $2.5 million in Q4 2009 compared to $2.4 million in Q4 2008; and decreased $2.8 million to $13.0 million in 2009 compared to $15.8 million in 2008 and was $8.9 million in 2007.

In 2007, Bear Swamp finalized a long-term agreement with LIPA to provide it with 345 MW of capacity to May 31, 2010 (approximately 55% of Bear Swamp's total capacity); and 100 MW thereafter, to April 30, 2021. In addition, Bear Swamp will provide LIPA with 12,200 MWh of super-peak and peak energy weekly, (approximately 35% of the plant's available energy production) at a fixed price, with an annual increase, over the 15 year term of the agreement. Bear Swamp has contracted with its joint venture partners for the off peak power supply necessary to produce the energy requirements of the LIPA agreement.

Bear Swamp – Mark-to-market

As mentioned above, Bear Swamp has contracted with its joint venture partners to provide the power necessary to produce the energy requirements of the LIPA contract. One of the contracts between Bear Swamp and Emera's joint venture partner is marked-to-market through earnings, as it does not meet the stringent accounting requirements of hedge accounting. As at December 31, 2009, the fair value of the net derivative asset was $6.2 million (December 31, 2008 – $4.9 million), which is subject to market volatility of power prices, and will reverse over the life of the agreement as it is realized. The agreement expires in 2021.

Income Taxes

Lucelec and GBPC equity earnings are recorded net of tax. Variations in income tax expense are largely affected by earnings and foreign exchange fluctuations, along with changes in the statutory tax rate

Corporate Costs and Other

Corporate costs and other millions of dollars (except earnings per common share)	Three months ended December 31		Year ended December 31		
	2009	2008	**2009**	2008	2007
Revenue	**$8.7**	$4.7	**$30.0**	$12.4	$0.3
Corporate costs	**8.9**	2.2	**20.0**	12.3	14.4
Financing charges	**8.9**	4.4	**22.6**	10.8	4.6
Income taxes	**(5.4)**	(5.6)	**(14.8)**	(9.1)	(8.9)
Total corporate costs and other	**$(3.7)**	$3.7	**$2.2**	$(1.6)	$(9.8)

Revenue

Revenue increased by $4.0 million to $8.7 million in Q4 2009 compared to $4.7 million in Q4 2008 and increased $17.6 million to $30.0 million for the year ended December 31, 2009, compared to $12.4 million in 2008 due to the financing to Brunswick Pipeline.

For the year ended December 31, 2008, revenue increased $12.1 million to $12.4 million compared to $0.3 million in 2007 for the same reasons explained above.

Corporate Costs

Corporate costs increased by $6.7 million in Q4 2009 compared to $2.2 million in Q4 2008 and increased $7.7 million to $20.0 million for the year ended December 31, 2009 compared to $12.3 million in 2008 due to an increase in deferred compensation costs offset by a reduction in management fees.

For the year ended December 31, 2008, corporate costs decreased $2.1 million to $12.3 million compared to $14.4 million in 2007 due to decreased depreciation expense.

Financing Charges

Financing charges increased $4.5 million to $8.9 million in Q4 2009 compared to $4.4 million in Q4 2008 and increased $11.8 million to $22.6 million for the year ended December 31, 2009 compared to $10.8 million in 2008 due primarily to increased debt to finance the construction of Brunswick Pipeline.

Financing charges increased $6.2 million to $10.8 million for the year ended December 31, 2008 compared to $4.6 million in 2007 for the same reasons noted in the explanation above.

Income Taxes

All businesses included in Other follow the future income taxes method of accounting for income taxes. Taxes are recognized on pre-tax income.

Income taxes increased $0.2 million to $(5.4) million in Q4 2009 compared to $(5.6) million in Q4 2008 and decreased $5.7 million to $(14.8) million for the year ended December 31, 2009 compared to $(9.1) million in 2008 due to an increase in corporate costs and financing charges for the year.

Income taxes decreased $0.2 million to $(9.1) million for the year ended December 31, 2008 compared to $(8.9) million in 2007 due to the same reasons noted in the explanation above.

OUTLOOK

Business Environment

Economic Environment

The global economy has experienced the worst economic downturn since the depression of the 1930s. Signs of recovery are now present, and the Bank of Canada is predicting modest economic growth for Canada in 2010. Parallel to this economic disruption has been the continued transformation of the energy industry from high emissions to lower emissions. This transformation provides opportunity for Emera over the next five years. The company has embarked upon a capital investment plan to increase the company's generation from renewable sources, to improve the transmission connections within our service territories, and to expand access to natural gas as we transition to a cleaner, greener company.

Environmental Legislation

In August 2009, the province of Nova Scotia enacted limits on greenhouse gas emissions. Caps have been set for years 2010 and 2020 inclusive. The company has stabilized and reduced emissions; continues to add cleaner, greener sources of electricity; and works with customers to manage energy usage. The company will continue to reduce green house gas emissions and comply with the new regulations.

The Canadian federal government has not formalized any greenhouse gas emission reduction regulations and have now signaled alignment with the United States' approach, which is tending towards cap and trade in the 2012 – 2014 timeframe for a starting year. The company continues to provide input to the Canadian federal government through their consultations.

NSPI

NSPI anticipates earning a regulated ROE within its allowed range in 2010. NSPI does not plan to file a general rate application in 2010. NSPI continues to implement its strategy focused on regulated investments in renewable energy and system reliability projects with a capital program budget of approximately $450 million in 2010. The company expects to finance its capital expenditures with funds from operations and debt.

Bangor Hydro

Bangor Hydro's USD earnings are expected to be slightly higher due to higher returns from new transmission investments. Bangor Hydro continues to execute on its transmission development plan, with approximately $130 million of large transmission projects in various stages of development. These projects, recoverable through regional transmission rates, are expected to provide returns on equity of 11.64%. In 2010, Bangor Hydro expects to invest approximately $48 million USD, including approximately $23 million USD for major transmission projects. The company expects to finance its capital expenditures with funds from operations and debt.

Pipelines

Pipelines earnings are expected to be higher in 2010 as Brunswick Pipeline will be operational for a full twelve months.

Other

Other net earnings and corporate costs are expected to be lower in 2010 due to higher financing charges.

LIQUIDITY AND CAPITAL RESOURCES

The company generates cash mainly through the operations of NSPI and Bangor Hydro, its two primary regulated utilities involved in the generation, transmission and distribution of electricity and Brunswick Pipeline. NSPI's and Bangor Hydro's customer bases are diversified by both sales volumes and revenues among residential, commercial, industrial and other customers. Circumstances that could affect the company's ability to generate cash include general economic downturns in its markets, the loss of one or more large customers, and regulatory decisions affecting customer rates. The UARB approved a FAM that reduces NSPI's exposure to fuel price volatility. The first rate adjustment under the FAM was approved by the UARB on December 9, 2009 and effective on January 1, 2010. NSPI and Bangor Hydro are each capable of paying dividends to Emera provided they do not breach their debt to capitalization ratios after giving effect to the dividend payment.

In addition to internally generated funds, Emera Inc. and NSPI have in aggregate access to $1.1 billion committed syndicated revolving bank lines of credit, of which approximately $600 million is undrawn and available as at December 31, 2009. Emera Inc. and NSPI have access to $600 million and $500 million of this credit facility respectively. NSPI has an active commercial paper program for up to $400 million, of which outstanding amounts are 100% backed by the bank lines referred to above and this results in an equal amount of that credit being considered drawn.

Emera's and NSPI's respective revolving credit facilities were successfully renewed in June 2009 and now mature in June 2010; they can be extended annually with the approval of the syndicated banks. At each maturity date, Emera and NSPI have the option to convert all amounts drawn to a one year non-revolving term credit.

In June 2009, the company negotiated a $300 million committed syndicated non-revolving bank credit facility as a bridge facility for Brunswick Pipeline replacing the $200 million facility which matured. This facility was repaid in December 2009.

In 2009, both Emera and NSPI had debt shelf prospectuses in the amounts of $400 million that expire in February 2010. In November 2009, Emera subsequently added $100 million to its shelf. As at December 31, 2009, Emera had $25 million remaining on its debt shelf prospectus while NSPI has issued the full amount of long-term debt allowed under its debt shelf prospectus.

Both Emera and NSPI intend to file respective $500 million shelf prospectuses in the first half of 2010.

As at December 31, 2009, the outstanding short-term debt is as follows:

As at December 31, 2009 millions of dollars	Maturity	Credit Line Committed	Utilized	Undrawn and Available
Nova Scotia Power - Operating credit facility	1 Year Revolver	$500	$235	$265
Emera - Operating and acquisition credit facility	1 Year Revolver	600	261	339
Bangor Hydro – in USD - Unsecured revolving facility	2 Year Revolver maturing June 2010	60	51	9

NSPI issues commercial paper, 100% backed by the syndicated bank line of credit, to finance short-term cash requirements and has accessed the market as required throughout 2009.

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

Debt Management

Emera

In November 2009, Emera completed a $225 million Series G medium-term note issue pursuant to its debt shelf prospectus. The Series G notes bear interest at the rate of 4.83% and yield 4.839% per annum until December 2, 2019.

In October 2009, Emera completed a $250 million Series F medium-term note issue pursuant to its debt shelf prospectus. The Series F notes bear interest at the rate of 4.10% and yield 4.108% per annum until October 20, 2014.

The proceeds from these issuances were used to pay down the $300 million non-revolving bank credit facility and the remainder was used to pay down short term debt.

The credit ratings issued by Dominion Bond Rating Service, Standard & Poor's, and Moody's Investor Services are as follows:

	DBRS	S&P	Moody's
Long-term corporate	BBB (high)	BBB+	Baa2

In September 2009, Standard & Poor's Rating Services ("S&P") revised the long-term credit rating to BBB+ from BBB following the implementation of the FAM, the completion of Brunswick Pipeline and improvements in the company's liquidity.

NSPI

In January 2009, NSPI completed a $50 million medium-term note issue, proceeds of which were used to pay down outstanding short-term debt. These notes bear interest at the rate of 5.75% and yield 5.455% per annum until October 2013.

In April 2009, NSPI redeemed the $125 million Series C preferred shares using short-term credit facilities.

In June 2009, NSPI redeemed $125 million long-term notes using short-term credit facilities.

In July 2009, NSPI completed a $200 million medium-term note issue, proceeds of which were used to pay down outstanding short-term debt. These notes bear interest at the rate of 5.95% and yield 5.974% per annum until July 27, 2039.

The weighted average coupon rate on NSPI's outstanding medium-term and debenture notes at December 31, 2009, was 6.80% (2008 – 6.84%). Approximately 38% of the debt matures over the next ten years; 59% matures between 2020 and 2039; and $50 million, or 3%, matures in 2097. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 4.87% as at December 31, 2009 (2008 – 6.12%).

NSPI has the following credit ratings:

	DBRS	S&P	Moody's
Corporate	N/A	BBB+	Baa1
Senior unsecured debt	A (low)	BBB+	Baa1
Preferred stock	Pfd-2 (low)	P-2 (low)	N/A
Commercial paper	R-1 (low)	A-1 (low)	P-2

In September 2009, S&P rating agency revised the long-term credit rating to BBB+ from BBB following the implementation of the FAM and improvements in the company's liquidity.

Bangor Hydro

The weighted-average coupon rate on Bangor Hydro's long-term debt outstanding at December 31, 2009, was 6.92% (2008 – 6.87%). Approximately 69% of the debt matures over the next 10 years; the remaining issues mature in 2020 and 2022. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 7.17% as of December 31, 2009 (2008 – 6.95%).

Bangor Hydro has no public debt, and accordingly has no requirement for public credit ratings. Bangor Hydro believes that its credit facility provides adequate access to capital to support current operations and a base level of capital expenditures. For additional capital needs, Bangor Hydro expects to have sufficient access to competitively priced funds in the unsecured debt market.

Contractual Obligations

The consolidated contractual obligations over the next five years and thereafter include:

millions of dollars							**Payments Due by Period**
	Total	2010	2011	2012	2013	2014	After 2014
Long-term debt	$2,442.7	$329.7	$8.5	$29.2	$365.4	$255.8	$1,454.1
Preferred shares issued by subsidiary	135.0	-	-	-	-	-	135.0
Operating leases	14.2	9.9	1.4	0.3	0.3	0.3	2.0
Purchase obligations	2,564.3	376.0	292.2	238.0	128.8	109.5	1,419.8
Capital obligations	133.0	128.7	4.3	-	-	-	-
Other long-term obligations	326.9	1.8	2.0	1.3	1.1	1.1	319.6
Total contractual obligations	$5,616.1	$846.1	$308.4	$268.8	$495.6	$366.7	$3,330.5

Operating lease obligations: Emera's operating lease obligations consist of operating lease agreements for office space, telecommunications services, and certain other equipment.

Purchase obligations: Emera has purchasing commitments for electricity from independent power producers, transportation of coal, outsourced management of the company's computer infrastructure, natural gas, transportation capacity on the Maritimes & Northeast Pipeline and fuel.

Capital obligations: The company has commitments to third parties to purchase turbines and other goods and services.

Other long-term obligations: The company has asset retirement and other long-term obligations.

The company expects to be able to meet its obligations with cash flows generated from operations.

Capital Resources

Capital expenditures, including AFUDC, were approximately $430 million for 2009 and included:

- $279 million in NSPI;
- $58 million in Bangor Hydro;
- $69 million in Brunswick Pipeline; and
- $21 million in Other.

PENSION FUNDING

For funding purposes, Emera determines required contributions to its defined benefit pension plans based on a smoothed asset value. 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 2010 for defined benefit pension plans will be approximately $42.2 million (2009 – $35.8 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

Emera's pension plan is managed with a diversified portfolio of asset classes, investment managers and geographic investments. Emera reviews the investment managers on a regular basis, and the plan's asset mix from time to time.

Emera's projected contributions to defined contribution pension plans are $1.6 million for 2010 (2009 – $1.4 million).

OFF-BALANCE SHEET ARRANGEMENTS

Upon privatization of the former provincially owned Nova Scotia Power Corporation ("NSPC") in 1992, NSPI became responsible for managing a portfolio of defeasance securities, which at December 31, 2009, totaled $1.0 billion, 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 72% 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.

TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera purchased natural gas transportation capacity totaling $12.5 million (2008 – $7.0 million) during the three months ended December 31, 2009, and $47.4 million (2008 – $29.4 million) during the year ended December 31, 2009, from the Maritimes & Northeast Pipeline, an investment under significant influence of the company. The amount is recognized in "Fuel for generation and purchased power" or netted against energy marketing margin in "Other revenue", and is measured at the exchange amount. At December 31, 2009, the amount payable to the related party is $4.6 million (2008 – $4.1 million), is non-interest bearing and is under normal credit terms.

DIVIDENDS AND PAYOUT RATIOS

In September 2009, the Board of Directors approved a quarterly dividend increase to $0.2725 per common share, reflecting an increase on an annualized basis to $1.09 per common share.

Emera Inc.’s common dividend rate was $1.03 ($0.2525 per quarter in Q1, Q2 and Q3; and $0.2725 in Q4) per common share in 2009 and $0.97 ($0.2375 per quarter in Q1, Q2 and Q3; and $0.2525 in Q4) for 2008, representing a payout ratio of approximately 65.1% for 2009 and 76% for 2008.

Effective September 25, 2009, Emera changed its Common Shareholders Dividend Reinvestment and Share Purchase Plan to provide for a discount of up to 5% from the average market price of Emera’s common shares for common shares purchased in connection with the reinvestment of cash dividends under the Plan. The Board of Directors of Emera also decided on September 25, 2009, that the discount would be 5% effective on and after the quarterly dividend payment on November 16, 2009, to shareholders of record on November 2, 2009.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Financial Risks and Financial Instruments

The company manages its exposure to foreign exchange, interest rate, and commodity risks in accordance with established risk management policies and procedures. The company uses financial instruments consisting mainly of foreign exchange forward contracts, interest rate options and swaps, and coal, oil and gas options and swaps. In addition, the company has contracts for the physical purchase and sale of natural gas, and physical and financial contracts held-for-trading (“HFT”). Collectively these contracts are referred to as derivatives.

The company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that qualify and are designated as contracts held for normal purchase or sale.

Derivatives that meet stringent documentation requirements, and can be proven to be effective both at the inception and over the term of the derivative, qualify for hedge accounting. Specifically, for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to “Other comprehensive loss” and recognized in earnings in the same period that the related hedged item is realized. Any ineffective portion of the change in the fair value of derivatives is recognized in net earnings in the reporting period.

For fair value hedges, the change in fair value of the hedging derivatives and the hedged item are recorded in net earnings. Any ineffective portion of the change in fair value is recognized in net earnings in the reporting period. The company also recognizes the change in the fair value of its HFT derivative in the income of the reporting period.

Where the documentation or effectiveness requirements of hedge accounting are not met, the derivative instruments are recognized at fair value with any changes in fair value recognized in net earnings in the reporting period.

HFT derivatives are recorded on the balance sheet at fair value, with changes normally recorded in net earnings of the period, unless deferred as a result of regulatory accounting. The company has not designated any financial instruments to be included in the HFT category.

NSPI has contracts for the purchase and sale of natural gas at its Tufts Cove generating station (“TUC”) that are considered HFT derivatives and accordingly are recognized on the balance sheet at fair value. This reflects NSPI’s history of buying and reselling any natural gas not used in the production of electricity at TUC. Changes in fair value of HFT derivatives are normally recognized in net earnings. In accordance with NSPI’s accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value to a regulatory asset or liability. In 2009, the UARB approved an amendment to NSPI’s accounting practice to include all Tufts Cove financial commodity hedges which are no longer required. This change in practice will impact the timing of recognition between "Fuel for generation and purchased power" and "Fuel adjustment" as a result of the FAM implemented in 2009.

The change in accounting practice is being applied prospectively, beginning in 2009, as required by the UARB.

Hedging Items Recognized on the Balance Sheet

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

millions of dollars	**December 31 2009**	December 31 2008
Inventory	**$22.2**	$(7.1)
Derivatives in a valid hedging relationship	**(29.5)**	(4.7)
Long-term debt	**0.1**	0.4
	$(7.2)	$(11.4)

Hedging Impact Recognized in Earnings

The company recognized in net earnings the following gains and losses related to the effective portion of hedging relationships under the following categories:

millions of dollars	Three months ended December 31		Year ended December 31	
	2009	2008	**2009**	2008
Financing income increase	**$2.8**	-	**$ 2.8**	-
Fuel and purchased power (increase) decrease	**(21.2)**	$10.9	**(43.2)**	$27.0
Financing charges decrease	**0.4**	1.5	**6.9**	1.0
Effectiveness (losses) gains	**$(18.0)**	$12.4	**$(33.5)**	$28.0

The effectiveness gains and losses reflected in the above table are offset in net earnings by the change in fair value hedged item realized in the period.

The company recognized in net earnings the following gains and losses related to the ineffective portion of hedging relationships under the following categories:

millions of dollars	Three months ended December 31		Year ended December 31	
	2009	2008	**2009**	2008
Fuel and purchased power (increase) decrease	**$(1.0)**	$0.0	**$(14.2)**	$(0.5)
Financing charges decrease (increase)	**0.3**	0.7	**(0.5)**	0.7
Ineffectiveness (losses) gains	**$(0.7)**	$0.7	**$(14.7)**	$0.2

Held-for-trading Items Recognized on the Balance Sheet

The company has recognized on the balance sheet a net held-for-trading derivatives asset of $9.4 million as at December 31, 2009 (2008 – $85.7 million).

Held-for-trading Derivatives Gains (Losses) Recognized in Earnings

The company has recognized the following realized and unrealized gains and losses with respect to HFT derivatives in earnings:

millions of dollars	Three months ended December 31		Year ended December 31	
	2009	2008	**2009**	2008
Electric revenue	**$(0.5)**	$(2.2)	**$0.1**	-
Other revenue	**12.6**	(5.0)	**6.9**	$3.6
Fuel and purchased power	**2.0**	(0.3)	**13.0**	(0.4)
Financing charges	**(0.1)**	(0.1)	**-**	(0.5)
Held-for-trading derivatives gains (losses)	**$14.0**	$(7.6)	**$20.0**	$2.7

As discussed in note 27 of Emera's financial statements at the reporting date, various valuation techniques are used to determine the fair value of derivative instruments. These may include quoted market prices, internal models using observable or non-observable market information.

The company has a derivative contract, as discussed in Significant Item, where no observable market exists, therefore modeling techniques are employed using assumptions reflective of current market rates, yield curves and forward prices, as applicable, to interpolate certain prices.

Business Risks

Measurement of Risk

Significant risk management activities for Emera are overseen by the Enterprise Risk Management Committee to ensure 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 and quality of earnings. These risks include, but are not limited to, exposure to commodity prices, foreign exchange, interest rates, credit risk, and regulatory risk.

The UARB approved the implementation of a FAM effective January 1, 2009, reducing NSPI's exposure to price volatility and providing a mechanism for NSPI to recover actual fuel costs, if different than what is recovered from customers in rates. The FAM mitigates the risk to NSPI's net earnings associated with fluctuations in commodity prices and foreign exchange. The first rate adjustment under the FAM was approved by the UARB on December 9, 2009 effective January 1, 2010.

Commodity Price Risk

Substantially all of the company's annual fuel requirement is subject to fluctuation in commodity market prices, prior to any commodity risk management activities. The company utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. The strategy is designed to reduce the effects from market volatility through agreements with staggered expiration dates, volume options, and varied pricing mechanisms.

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 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 at December 31, 2009 is as follows:

- 2010 – 84%
- 2011 – 34%
- 2012 – 15%

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 2010 and 2011, NSPI currently does not have heavy fuel oil hedging requirements.

Natural Gas
NSPI has entered into multi-year contracts to purchase approximately 60,000 mmbtu of natural gas per day in 2010, and 38,000 mmbtu of natural gas per day in 2011. 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. Fixed price gas volumes not required for generation will be resold into the gas market with the margin hedged using financial instruments. As at December 31, 2009, amounts of natural gas volumes that have been economically and/or financially hedged and contracted are approximately as follows:

- 2010 – 94%
- 2011 – 32%

Purchased Power
Emera, along with its joint venture partner, has entered into a contract with Bear Swamp to fix the price of power necessary to produce the energy requirements of the LIPA contract. As at December 31, 2009, amounts of purchased power Emera has hedged are approximately as follows:

- 2010 – 96%
- 2011 – 100%
- 2012 – 96%
- 2013 – 11%

Foreign Exchange Risk

The risk due to fluctuation of the CAD against the USD for the cost of fuel is measured and managed. In 2010, NSPI expects approximately 68% of its anticipated net fuel costs to be denominated in USD. USD from sales of surplus natural gas will provide a natural hedge against a portion of USD fuel costs.

NSPI enters into foreign exchange forward and swap contracts to limit the exposure of currency rate fluctuations on fuel purchases. Currency forwards are used to fix the CAD cost to acquire USD, reducing exposure to currency rate fluctuations. Forward contracts to buy USD $331.0 million are in place at a weighted average rate of $1.09, representing 89% of 2010 anticipated USD requirements. Forward contracts to buy USD $471.5 million in 2011 through 2013 at a weighted average rate of $1.01 were in place at December 31, 2009. These contracts cover 42% of anticipated USD requirements in these years.

NSPI uses foreign exchange forward contracts to hedge the currency risk for capital projects and receivables denominated in foreign currencies. Forward contracts to buy USD $0.9 million are in place at a weighted average rate of $1.00 for capital projects in 2010. Forward contracts to buy € 30.3 million are in place at a weighted average rate of 1.56 (versus CAD) for capital projects in 2010. Forward contracts to sell USD $39.0 million are in place at a weighted average rate of $1.25 to hedge a portion of receivables in 2010.

Brunswick Pipeline uses forward contracts to hedge the currency risk associated with revenue streams denominated in foreign currencies. Forward contracts to sell USD $62.0 million are in place in 2010 and 2011 at a weighted average rate of $1.16.

Interest Rate Risk

Emera manages interest rate risk through a combination of fixed and floating borrowing and a hedging program. Floating-rate debt is estimated to represent approximately 24% of total debt in 2010. The company has no interest rate hedging contracts outstanding as at December 31, 2009.

Credit Risk

Credit risk arising as a result of contractual obligations between the corporation and other counterparties is managed by assessing the counterparties' financial creditworthiness prior to assigning credit limits based on the Board of Directors' approved credit policies. The company frequently uses collateral agreements within its negotiated master agreements to further mitigate credit exposure.

Labour Risk

NSPI has a contract with its union which will expire in 2012 and Bangor Hydro has a contract with its union which expires in mid 2010.

Regulatory Risks

Nova Scotia Power

NSPI faces risk with respect to the timeliness and certainty of full recovery of costs. The adoption and implementation of the FAM, effective January 1, 2009, has helped NSPI manage that risk. The UARB oversees the FAM, including review of fuel costs, contracts and transactions. The first rate adjustment under the FAM, effective on January 1, 2010, was approved by the UARB on December 9, 2009. The FAM will help ensure customer rates reflect the actual price of the fuel used to make electricity. Concurrent with the implementation of the FAM in 2009, NSPI's regulated ROE range was reduced by 0.2%, changing its regulated ROE range to 9.1% to 9.6%, with rates set at 9.35%.

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 costs.

Bangor Hydro's distribution business operates under the regulation of the MPUC and operates under a traditional cost-of-service regulatory structure. Until December 31, 2007, Bangor Hydro operated under an Alternate Rate Plan which governed distribution rates. In late 2007, the MPUC approved a modest increase in distribution rates under the traditional cost-of-service regulatory structure. In the event that costs rise faster than revenues, Bangor Hydro would have the ability to return to the MPUC to request a further increase in rates.

The transmission business of Bangor Hydro is primarily regulated by the FERC. The rates charged are determined by formula and are adjusted on an annual basis. Bangor Hydro is a participating transmission owner within the Regional Transmission Organization for New England, and its operations are therefore linked with the transmission operations of all of New England. Bangor Hydro's ROE on its transmission assets, along with added incentives is determined by FERC along with the regional transmission owners.

Bangor Hydro also has the ability to recover stranded costs of both regulatory assets and purchasing power at above-market prices. This ability eliminates the commodity risk involved with fixed price purchase power contracts.

Metering, billing and settlement services for power suppliers are provided directly by Bangor Hydro within its service territory, and Bangor Hydro is permitted to recover all prudently incurred costs for these services.

Environment

Corporate Environmental Governance

Emera is committed to operating in a manner that is respectful and protective of the environment, and in full compliance with legal requirements and company policy. Emera and its wholly-owned subsidiaries have implemented this policy through development and application of environmental management systems ("EMS").

Implementation of EMS has provided a systematic focus on environmental issues so risks are identified and managed proactively. All areas of Emera undertook initiatives in 2009 to reduce potential environmental risks and associated costs. Activities included, but were not limited to, reducing air emissions, protecting water resources, and continued management of PCB contaminated electrical equipment.

Conformance with legislative and company requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the 2009 audits. Plans are in place to promptly address any audit finding and continually improve the environmental management of the operations.

Oversight of environmental matters is carried out by the Board of Directors of all Emera operating companies or committees of the Board of Directors with specific environmental responsibilities. In addition, an Environmental Council, made up of senior Emera employees, with working accountability for environment, continues to guide the implementation of programs that address key environmental issues. In addition to programs for employees, the EMS procedures of all wholly-owned subsidiaries include planning, implementing and monitoring of contractors' performance.

In 2007, NSPI was audited by the Canadian Electricity Association ("CEA") to verify the quality of its environmental reporting and management systems. The auditor from the CEA concluded that NSPI had "robust programs, environmental leadership and a strong, mature EMS."

Climate Change and Air 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, improved efficiency of converting natural gas to electricity and adding and contracting for new renewable energy sources to the generation portfolio.

In January 2007, the Nova Scotia government approved the Renewable Energy Standard Regulation to increase the percentage of renewable energy in the generation mix. In October 2009, the RES was amended. The target date for 5% 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% of renewable energy, is unchanged.

In April 2007, the province of Nova Scotia enacted an Act Respecting Environmental Goals and Sustainable Prosperity. Within this act, there is an objective to reduce provincial greenhouse gas emissions to 10% below 1990 levels by 2020. In January 2009, the province released its 2009 Energy Strategy and Climate Change Action Plan. These documents provide the elements of the plan to achieve this objective. In August 2009, the province enacted regulations to cap green house gas emissions from the electricity sector in Nova Scotia.

Greenhouse gas emissions from NSPI facilities are capped beginning in 2010 through to 2020. The 2010 to 2012 caps will be achieved by the continued success of energy efficiency and conservation programs and the addition of renewable energy to meet the 2010 provincial renewable energy standards. The regulations also include a transmission incentive compliance mechanism recognizing expenditures on transmission which facilitates additional renewable energy sources. Up to 3% of the annual cap can be offset in this way to 2019. Further, the 2010 to 2020 period years are combined to form multi-year compliance periods recognizing the variability in electricity supply sources and demand.

It is anticipated that the 2013 – 2015 caps will be achieved by flattening load growth through successful energy efficiency and conservation programs and adding renewable energy to meet the provincial 2013 renewable energy standards. NSPI has also piloted co-firing of local biomass, which can be a carbon neutral fuel, in the coal fired power plants.

Beyond 2015, reduced greenhouse gas emissions will be achieved through a combination of additional renewable energy, co-firing of biomass in existing coal power plants, import of non-emitting energy and energy efficiency and conservation.

The Canadian federal government has not formalized any greenhouse gas emission reduction regulations and have now signaled alignment with the US approach which is tending towards cap and trade in the 2012 to 2014 timeframe for a starting year. NSPI continues to provide input to the Canadian federal government as it proceeds with its consultations.

In 2008, NSPI carried out extensive testing on mercury abatement technology in its coal power plants. A capital program to add sorbent injection to each of the seven pulverized fuel coal units was completed in 2009. This will allow NSPI to meet the mercury emission cap of 65 kg established by the province effective 2010.

NSPI has completed its capital program of retrofitting low nitrogen oxide combustion firing systems on six of its seven pulverized fuel coal units. NSPI now meets the nitrogen oxide emission cap of 21,365 tonnes per year established by the province effective 2009.

NSPI continues to meet its emission cap on sulphur dioxide emissions by the use of compliant fuel.

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

DISCLOSURE AND INTERNAL CONTROLS

Emera's management is responsible for establishing and maintaining 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. The objective of this instrument is to improve the quality, reliability and transparency of information that is filed or submitted under securities legislation.

The President and Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of company employees, DC&P and ICFR to provide reasonable assurance that material information is reported to them on a timely basis; financial reporting is reliable; and financial statements prepared for external purposes are in accordance with CGAAP.

The President and Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of company employees, the effectiveness of Emera and its consolidated subsidiaries' DC&P and ICFR and based on that evaluation, have concluded DC&P and ICFR were effective at December 31, 2009.

There have been no changes in Emera or its consolidated subsidiaries' ICFR during the period beginning on January 1, 2009 and ended on December 31, 2009, 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 requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to rate-regulation, the determination of post-retirement employee benefits, unbilled revenue, contract receivable, asset retirement obligations, useful lives for depreciable assets, and goodwill impairment assessments. Actual results may differ from these estimates.

Rate Regulation

The rate-regulated accounting policies of NSPI, Bangor Hydro and Brunswick Pipeline may differ from accounting policies for non-rate-regulated companies. NSPI and Bangor Hydro 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.

Similar to most North American pension plans, Emera experienced negative asset returns during 2008 and positive asset returns during 2009. Consistent with CGAAP and Emera's accounting policy, the company amortizes the net actuarial gain or loss, which exceeds 10% of the greater of the accrued benefit obligation ("ABO") and the market-related value of assets, over active plan members' average remaining service period, which is currently 10 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 ABO.

The discount rate used to determine benefit costs is based on high quality long-term Canadian corporate bonds for NSPI's pension plan and US corporate bonds for Bangor Hydro's pension plan. The discount rate is determined with reference to bonds which have the same duration as the ABO as at January 1 of the fiscal year rounded to the nearest 25 basis points. For benefit cost purposes, NSPI's rate was 7.50% for 2009 (2008 – 5.75%) and Bangor Hydro's rate was 6.75% for 2009 (2008 – 6.75%).

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 7.25% for 2009 (2008 – 7.50%) for NSPI and 8.00% for 2009 (2008 – 8.00%) for Bangor Hydro.

The reported benefit cost for 2009, based on management's best estimate assumptions, is $20.8 million. While there are numerous assumptions which are used to determine the benefit cost, the discount rate and asset return assumptions have an impact on the calculations. The following shows the impact on 2009 benefit cost of a 25 basis point change (0.25%) in the discount rate and asset return assumptions:

	2009	2008	2009	2008
millions of dollars	Increase 0.25%	Increase 0.25%	Decrease 0.25%	Decrease 0.25%
Discount rate assumption	$(1.3)	$(3.5)	$1.4	$3.6
Asset return assumption	$(1.9)	$(1.7)	$1.9	$1.7

The sensitivity to the discount rate assumption is significantly lower for 2009 benefit cost than in recent years because the net unamortized gains and losses subject to amortization fall within the 10% corridor. As such, for the current year, small changes to the discount rate assumption do not impact the amount of actuarial gains and losses being amortized and included in the calculation of benefit cost.

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. 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. 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, 2009, unbilled revenues amount to $98.4 million (2008 – $89.7 million) on a base of annual electric revenues of approximately $1.4 billion (2008 – $1.3 billion).

Contract Receivable

NSPI's existing natural gas purchase agreement includes a price adjustment clause covering three years of natural gas purchases. The clause states that NSPI will pay for all gas purchases at the agreed contract price, but will be entitled to a price rebate on a portion of the volumes. The first settlement took place in November 2007 for purchases to the end of October 2007. The next settlement will be in November 2010. Management has made a best estimate of the price rebate based on the contract specifications using actual and forward market pricing and recorded it in "Accounts receivable".

Asset Retirement Obligations

The company recognizes asset retirement obligations for property, plant and equipment in the period in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of the liability is described as the amount at which the liability could be settled in a current transaction between willing parties. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of the company's credit standing. Determining asset retirement obligations requires estimating the life of the related asset and the costs of activities such as demolition, restoration and remedial work based on present-day methods and technologies.

As part of the 2003 NSPI depreciation settlement, the UARB included the amount of future expenditures associated with the removal of generation facilities. NSPI believes that it will continue to be able to recover asset retirement obligations through rates. Accordingly, changes to the asset retirement obligations, or cost recognition attributable to changes in the factors discussed above, should not impact the results of operations of the company.

As at December 31, 2009, the asset retirement obligations recorded on the balance sheet were $104.5 million (2008 – $88.0 million). The company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $337.3 million, which will be incurred between 2010 and 2061. The majority of these costs will be incurred between 2020 and 2039.

Property, Plant and Equipment

Property, plant and equipment represents 55.4% 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 size of the company's property, plant and equipment, changes in estimated depreciation rates can have an impact on depreciation expense.

Depreciation is calculated on a straight-line basis over the estimated service life of the asset. The estimated useful lives of the assets are largely based on formal depreciation studies, which are conducted from time to time.

In 2002, NSPI commissioned a depreciation study by an external consultant. The study was filed with the UARB in 2003. A settlement agreement on the matter was reached with all interveners, which recommended a four-year phase-in of new depreciation rates, which, based on assets in service in the study, would reach an overall increase in depreciation expense of $20 million by 2007. The UARB approved the settlement. NSPI began phasing the new rates in 2004. In its rate decision for 2005, the UARB deferred the scheduled phase-in for 2005. In the rate decision for 2006, the UARB included the phase-in of year-two in rates. In its February 5, 2007 decision, the UARB postponed the phase-in of year-three rates until the next rate application. In its November 5, 2008 decision, the UARB approved year-three phase-in rates effective January 1, 2009.

Goodwill Impairment Assessments

Goodwill represents the excess of the acquisition purchase price for Bangor Hydro 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 may be below its carrying value. Emera performs its annual impairment test as at March 31.

Impairment assessments are based on fair market value assessments. Fair market value is determined by use of net present value financial models that incorporate management's assumptions about future profitability. There was no impairment provision required in 2009 or 2008.

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

The Canadian Institute of Chartered Accountants ("CICA") has issued new accounting Standard 3064 Goodwill and Intangibles, various new accounting standards related to accounting for rate-regulated operations, Emerging Issues Committee Abstract of Issue Discussed 173 Credit Risk and the Fair Value of Financial Assets and Financial Liabilities ("EIC-173"), and amendments to Standard 3862 Financial Instruments – Disclosures, which are applicable to Emera's 2009 fiscal year. The following provides more information on each change.

Goodwill and Intangibles

Under Standard 3064, goodwill requirements have not changed. The requirements for intangible assets now clarify that costs may only be deferred when they relate to an item that meets the definition of an asset. An intangible asset must be identifiable; be a resource over which the company has control; generate probable future economic benefits; and have a reliably measurable cost. Further information can be found in note 17 to the financial statements.

The company has applied the new Standard retrospectively with restatement of prior periods, which resulted in the following reclassifications:

As at Millions of dollars	December 31 2008	December 31 2007
Assets		
Property, plant and equipment	$(86.2)	$(76.0)
Construction work in progress	(15.6)	(7.8)
Intangibles	$101.8	$83.8

Rate-Regulated Operations

These new standards include removing the temporary exemption in Standard 1100 Generally Accepted Accounting Principles pertaining to the application of the standard to the recognition and measurement of assets and liabilities arising from rate regulation; and amending Standard 3465 Income Taxes to require the recognition of future income tax assets and liabilities for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers.

As a result of the new standards, Emera recognized all of its future income tax assets and liabilities of its wholly-owned subsidiaries. In accordance with the company's rate-regulated accounting policies covering income taxes, Emera deferred any future income taxes to a regulatory asset or liability where the future income taxes are expected to be included in future rates or tolls. Further information can be found in note 9 to the financial statements. The company has applied the new standard retrospectively without restatement of prior periods, which resulted in the following increases:

millions of dollars	January 1 2009
Assets	
Current assets	
Future income tax assets	$31.6
Other assets	47.4
	$79.0
Liabilities and Shareholders' Equity	
Future income tax liabilities	$79.0
	$79.0

In accordance with Standard 1100, Emera determined all of its regulatory assets and liabilities qualified for recognition under CGAAP as well as US Financial Accounting Standard Board's Accounting Standard Codification 980, Regulated Operations.

Financial Instruments

EIC-173 requires that a company take into account its own credit risk and the credit risk of the counterparty in determining the fair value of financial assets and financial liabilities. The company has applied the new requirements retrospectively without restatement of prior periods, the effect of which was immaterial.

Financial Instruments – Disclosures

In June 2009, the CICA issued amendments to Standard 3862 Financial Instruments – Disclosures to include additional disclosure requirements about the fair value measurement of financial instruments and to enhance liquidity risk disclosures. The company has reflected the additional disclosures in its 2009 annual audited consolidated financial statements. The new accounting standard covers disclosure only and had no effect on the financial results of the company. Further information can be found in note 27 to the financial statements.

The accounting policy changes listed above did not affect earnings.

Derivative Financial & Commodity Instruments

Accounting for the impact of rate regulation

The UARB allows NSPI to apply hedge accounting to hedging relationships that do not meet the probability requirements of Standard 3865 Hedges due to NSPI's ability to fuel switch at TUC. Absent UARB approval, NSPI would be required to recognize the change in fair value of these derivatives in net earnings.

In 2009, the UARB approved an amendment to NSPI's accounting practice to include all TUC financial commodity hedges which are no longer required. This change in practice will impact the timing of recognition between "Fuel for generation and purchased power" and "Fuel adjustment" as a result of the FAM implemented in 2009. The change in accounting practice is being applied prospectively, beginning in 2009, as required by the UARB.

As at December 31, 2009, the change in accounting practice resulted in $0.4 million additional interest costs recognized in "Financing charges" ($0.3 million after-tax) and $0.4 million increase in the FAM regulatory liability in "Other Liabilities".

Future Accounting Policy Changes

Changeover to International Financial Reporting Standards ("IFRS")

In February 2008, the CICA announced that Canadian GAAP for publicly accountable enterprises will be replaced by International Financial Reporting Standards ("IFRS") for fiscal years beginning on or after January 1, 2011. Accordingly, the conversion from Canadian GAAP to IFRS will be applicable to the company's reporting for the first quarter of 2011, for which the current and comparative information will be prepared in accordance with IFRS. The company expects the transition to IFRS to impact accounting, financial reporting, internal controls over financial reporting, information systems and processes, and certain contractual arrangements. The most significant areas of impact are property, plant and equipment ("PP&E"), regulatory assets and liabilities, and employee future benefits. The actual financial impacts on these areas are, however, dependent on the outcome of the International Accounting Standard Board ("IASB") Exposure Draft ("ED") on Rate Regulated Activities ("RRA") which was issued in July 2009.

The IASB's ED on RRA proposes to allow the continued recognition of assets and liabilities arising from certain rate-regulated activities. IFRS does not currently provide guidance on accounting for the effects of rate regulation and the ED represents a significant change from current IFRS practices. The ED was open to comment until November 20, 2009 and the original timeline proposed a decision on a new standard in June 2010. The company believes it is highly unlikely this original time table will be met, based on the volume of comment letters received, varied responses and other factors currently affecting the IASB.

The outcome of the ED is of particular importance to Emera given the extent of regulatory assets and liabilities arising in NSPI, Bangor Hydro, Brunswick Pipeline and M&NP. If recognizing the economic impacts of regulatory activities is not permitted under IFRS, the financial accounting impact will be significant. It is possible that all its current regulatory assets and liabilities will be written off on transition to IFRS and on an on-going basis net earnings will be subject to volatility. The uncertainty surrounding the timing and eventual adoption of a RRA standard by the IASB poses a significant challenge in the company's adoption of IFRS, but is being managed through our overall approach to the project and the timing of project activities.

Given the significant impact the RRA ED could have on the Company's financial reporting and the continued uncertainty around the IASB's adoption of a RRA standard and the timing of a decision, the Company is considering the option of adopting US GAAP for external financial reporting purposes as part of its contingency planning. An update on the ED project is expected following the IASB's scheduled meeting in February 2010. This update will be critical in determining the expected timing and direction of a final decision on the ED and the application of RRA under IFRS.

Transition Activities

The company began its IFRS transition activities in 2008. KPMG was engaged in a technical advisory role and a four phased project approach was adopted to manage a project of this scope and complexity. Currently, the project is proceeding on schedule to achieve its required milestones. The following is a brief overview of the activities of each phase and current status.

Phase One: Preliminary Assessment - Completed

Phase One involved a high-level assessment of the most significant differences between Canadian GAAP and IFRS to determine the areas most likely to impact the company. The assessment was completed in 2008 and was critical to establishing the initial project plan and resources required to carry out the activities of the subsequent project phases. Internal resources were dedicated to the project to ensure its completion within the required timeline. This phase also included the development of the Project Charter, Governance Structure and the Project Management Office to support the subsequent phases.

Phase Two: Detailed Assessment - Completed

Phase Two involved further, more detailed assessment of Canadian GAAP – IFRS differences. All accounting and disclosure differences were analyzed to determine if they resulted in a high/medium/low impact on net earnings, the balance sheet and financial statement disclosures. The level of difficulty to implement changes was also assessed. The areas with the highest potential to affect the company are regulatory assets and liabilities, PP&E, employee future benefits, hedge accounting, ARO and IFRS 1. IFRS 1 is the IFRS standard that sets out transitional requirements and exemptions available upon first time adoption of IFRS.

An Information Technology ("IT") initiatives assessment and system landscape review was performed as part of this phase, along with the development of initial IFRS training and communication plans. The Detailed Assessment phase was completed in March 2009 and provided information required to create a more detailed project plan.

Phase Three: Design – In Progress

Phase Three began in Q2 of 2009 with the preparation of technical papers that further analyzed the differences between Emera's current accounting treatments and those required under IFRS to determine impacts on financial reporting processes, IT systems, and disclosure and internal controls over financial reporting. Technical papers support approval of the company's new accounting policies under IFRS and while significant progress has been made on these papers, final decisions on those accounting policy changes most likely to have a significant impact cannot be finalized as a result of the uncertainty of the adoption of the IASB ED. The ED impacts the extent of accounting differences and choices available in these areas and as a result, the specific financial impacts of such policy changes are not yet determinable. Implementation of accounting policies not impacted by the ED are not expected to result in material changes.

Despite the lack of certainty regarding the IASB ED, detailed design activities have commenced for known financial reporting process and system changes. This has involved the development of an "IT Solutions Strategy" and "January 2010 Readiness" activities and will ensure the achievement of critical project milestones.

The IT Solutions Strategy was developed in Q3 and Q4 of 2009 and addressed the need for a "Transition Solution" and an "End State Solution". The Transition Solution supports the creation of comparative IFRS data for 2010 and the End State Solution supports post-2010 reporting under both IFRS and in accordance with regulatory requirements. The extent to which financial statements prepared for the company's regulators and those prepared under IFRS will differ and cannot be determined until the outcome of the ED is known. Therefore, the company has adopted a phased approach to the design, development, testing and implementation of IT systems change. Phases or "releases" required to be implemented before the outcome of the ED is known will maintain the flexibility to report with or without a RRA standard. The first release of the Transition Solution was designed in Q4 2009 and was implemented in January 2010. This supports the capture of transactional PP&E data throughout 2010 as required for IFRS reporting. The End State IT Solution requires upgrades and/or modifications to several of Emera's financial reporting systems and software in 2010.

Finalization of technical papers, draft IFRS financial statements and design activities will continue throughout 2010 until the outcome of the ED is known.

Phase Four: Implementation – In Progress

Phase Four began in Q4 2009 and involves implementing changes to business and accounting processes across the organization, along with formal documentation of all approved accounting policies and procedures in accordance with IFRS. The impact of accounting policy changes will be quantified in this phase and the opening IFRS balance sheet, as at January 1, 2010, will be prepared.

IT solutions and system upgrades will be implemented in this phase. The first release of the Transition Solution was successfully implemented in January 2010 and involved setting up the financial reporting system to capture PP&E data on the component basis required for IFRS. Activities to upgrade and modify IT systems started in Q4 2009 and will continue through 2010.

In regards to January 2010 Readiness activities, the Company updated its hedge documentation prior to December 31, 2009 to ensure its existing hedges qualified for the desired accounting treatment under IFRS.

Phase Four activities will continue throughout 2010 and into 2011 when the Company goes live under IFRS.

Business Combinations

In January 2009, the CICA issued Standard 1582 Business Combinations ("1582") together with Standard 1601 Consolidated Financial Statements ("1601") and Standard 1602 Non-Controlling Interests ("1602") applicable to Emera's 2011 fiscal year, replacing Standard 1581 Business Combinations and Standard 1600 Consolidated Financial Statements.

Adoption of 1582 will change the measurement of non-controlling interest and goodwill for future acquisitions. Changes also include expensing acquisition-related transaction costs rather than including the costs as part of the purchase price and the disallowing recognition of restructuring accruals by the acquirer. Standard 1582 will affect the recognition of business combinations completed by the company on or after January 2011.

Standard 1601 establishes standards for the preparation of consolidated financial statements and Standard 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of 1601 and 1602 will result in non-controlling interests being presented on the consolidated balance sheet as components of equity rather than as liabilities. Also, net earnings and components of other comprehensive income attributable to the owners of the parent and to the non-controlling interests are required to be separately disclosed on the statement of earnings. The company is currently assessing the effect of 1601 and 1602 on its financial statements but does not expect a material impact.

SUMMARY OF QUARTERLY RESULTS

For the quarter ended
millions of dollars (except earnings per common share)

	Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008	Q3 2008	Q2 2008	Q1 2008
Total revenues	**$389.1**	$338.5	$334.2	$403.7	$337.3	$295.8	$317.6	$381.2
Net earnings applicable to common shares	**37.5**	37.3	38.1	62.8	25.3	6.5	42.9	69.4
Earnings per common share – basic	**0.33**	0.33	0.34	0.56	0.23	0.05	0.39	0.62
Earnings per common share – diluted	**0.33**	0.33	0.33	0.53	0.22	0.05	0.37	0.58

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