Emera

Annual Financial Report 2006

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Letter to shareholders

Fellow Shareholders

I am encouraged by the progress our company has made in 2006. With strong governance and executive leadership in place at our operating subsidiaries, your management team was able to devote its full energies to our growth agenda.

We are tackling the growth challenge on two fronts. We are taking steps to improve the returns in the businesses we currently own. At the same time, we are building Emera with new, higher return investments appropriate to our skill set and risk profile.

Improving Returns In Existing Businesses

Our largest subsidiary, Nova Scotia Power, earned $104.3 million in 2006, providing a return on equity of 9.7%.

NSPI is a solid utility operation. Its challenge over the past several years has been to have regulated revenue increases keep pace with rising fuel costs. The company has had no option but to file a series of general rate applications over the past five years, which, by their nature, take months to conclude. If the timing of new rates and higher fuel costs is not in sync, or if actual fuel costs are higher than what was forecast when annual rates were set, the utility's earnings are negatively affected.

Critical to Nova Scotia Power's ability to deliver more reliable earnings is the introduction of a regulatory mechanism to recover actual fuel costs on a timely basis. The company made significant progress toward this important goal in recent months with the 2007 Rate Settlement. A key element of the negotiated settlement that NSPI and key stakeholders reached on the utility's 2007 rate application is an agreement in principle to implement a fuel adjustment mechanism (FAM) for the utility. Hearings to determine the structure of the FAM will begin in June of this year. When implemented, the FAM will substantially improve the predictability of the utility's annual earnings and cash flow, providing investors with an appropriate and consistent risk-adjusted return.

Bangor Hydro earned $16.8 million in 2006, representing an improved return on equity of 6.9%. Since we acquired Bangor Hydro in 2001, Emera has had great success streamlining the cost structure, improving customer service and enhancing the utility's relationship with its regulator. Unfortunately, weak economic conditions in its service territory and the stronger Canadian dollar have offset efficiency gains, so returns have been somewhat lower than we expected. However, cash flows have been strong, as BHE recovers its stranded asset base. Emera is reinvesting that cash in the Northeast Reliability Interconnect (NRI), a high voltage electricity transmission line connecting New Brunswick and Maine. We will effectively transform Bangor's asset base, replacing low-return, non-productive stranded assets with high-return operational assets. The NRI is entitled to a return on equity of 12.4%, so the addition of this new earnings stream will increase our overall return on our Bangor Hydro investment.

Our joint venture with Brookfield Power in the 600 MW Bear Swamp merchant hydro facility in Massachusetts is going well. Soft market conditions in 2006 reduced the facility's earnings, but the bigger story with Bear Swamp is a good one. When we made that acquisition, we recognized the importance of that asset to its market. Our market assessment and instincts were right, as recent developments demonstrate. Investors will recall that Emera/Brookfield acquired that 600 MW facility in 2005 for US $92 million. In comparison, in 2006, the Northfield Mountain facility elsewhere in the state changed hands for a dramatically higher amount. The Independent System Operator (ISO) in the region recently approved capacity payments to generators, which will add over $5 million to Bear Swamp's annual net earnings. In addition, the facility is flexible enough to be able to provide a suite of load management services that the ISO values and is prepared to pay for. We are also working to finalize an agreement to contract one unit of the facility. Our goal is to provide an enhanced predictability to earnings while preserving an opportunity for upside potential that is key to realizing full value in a merchant operation.

We are proud to operate the first and only energy services business in Atlantic Canada. Emera Energy

Services (EES) has grown from a standing start in 2002 to contribute $9 million to net income in 2006. EES manages energy assets primarily on behalf of customers in Maritime Canada and the northeast United States. In 2006, EES transacted 100,500,000 MMBtu of gas and 766 GWh of power and provided other energy services. As importantly, the market intelligence EES gathers on a daily basis supports our growth agenda, enabling us to better assess investment opportunities, and optimize our assets and investments.

Building the Business with Higher Return Investments

The highlight of 2006 was our investment in Brunswick Pipeline. This proposed pipeline will deliver natural gas from the new Canaport™ Liquefied Natural Gas terminal in Saint John to US markets. This is a niche opportunity, which we were able to develop because of our existing investment in the Maritimes & Northeast Pipeline. It is also a great example of capitalizing on partnerships to expand Emera's scope and reach. We will be working with our existing M&NP partners, Spectra Energy Corp. (formerly Duke Energy), which complements our skill set and mitigates our risk. National Energy Board hearings concluded late in 2006, and we expect a decision by June of this year. If approved, the pipeline is expected to be in service by the end of 2008, and is forecast to add approximately $15 million to Emera's net earnings by 2010.

Early in 2007, Emera acquired a 19% interest in St. Lucia Electricity Services Limited (Lucelec). Our decision to invest in the Caribbean was strategically driven. The competition for North American assets is extremely intense at the moment, with an influx of financial players driving valuations that we as operators believe are excessive. Accordingly, we are looking for other opportunities for Emera to advance its growth agenda in the medium term. The Caribbean market is a reasonable extension for any North American based business, and we believe the opportunity is worth investigating further. The modest investment in Lucelec gives us a low risk vehicle to do that.

We have identified several key criteria that need to be in place for us to invest additional capital in the region. Opportunities must be in growth markets where our operational skills can bring value, with supportive regulatory environments, and quality local players that we can partner with. We will be looking hard at the region, and as we learn more through this assessment process, we will determine whether the Caribbean market is where we want to be.

Financial Strength is Key to Future Success

Emera's consolidated net earnings were $125.8 million in 2006, with earnings per share of $1.14. That represents a 9.1% return on common equity. We paid dividends of 89 cents per share, resulting in a payout ratio of 78%.

Emera's common shares closed the year at $22.60. Together, capital appreciation and reinvested dividends combined to deliver shareholders a total return for the year of 11.6%.

Based on my conversations with investors through the year, I know the fact that we are finally able to demonstrate some earnings growth potential is viewed favourably. Investors also tell me that greater liquidity in our stock would be a positive thing. That change will not happen overnight, but I believe we have an interesting investment proposition, and will continue to work to get the story out.

Emera's total asset base was $4.1 billion at December 31, 2006. Over 90% of our assets are in regulated businesses, with Nova Scotia Power the largest component at 75% of total assets. From an earnings perspective, NSPI and BHE together comprise approximately 90% of Emera's consolidated earnings for 2006.

In Q2 2006, Standard & Poor's (S&P) rating agency lowered the long term corporate debt credit ratings of Emera from BBB+ to BBB. A key reason for the change was S&P's concern about recovery of fuel expenses in Nova Scotia Power. Our two other rating services, Dominion Bond Rating Service and Moody's Investor Services, continue to rate Emera at BBB(high) and Baa2 respectively. To date, the change has not had a material impact on our business. Over time, as Nova Scotia Power implements a fuel adjustment mechanism, and our new investments start to contribute cash flows, we will encourage S&P to revisit their rating, with the objective of restoring the BBB+.

Our financial goals are straightforward. We are working to:

- Ensure our electric utilities earn returns consistent with our industry peers every year.
- Grow and diversify our earnings base such that eventually 35% of our earnings come from investments other than Nova Scotia Power.
- Deliver annual consolidated earnings growth of 4%–6%.
- Maintain our BBB bond rating in the medium term, and eventually improve it.
- Grow the annual dividend and sustain the payout ratio within a range of 70%–75%.

Leadership Is Critical

As I noted at the beginning, Emera's management and Board of Directors were able to focus exclusively on our growth agenda in 2006 as a result of organizational changes that gave Nova Scotia Power its own Executive leadership and Board. Ralph Tedesco took over from me as President and CEO of NSPI in May of 2006, and now reports to a newly configured NSPI Board of Directors distinct from that of Emera, chaired by John McLennan. That structure is similar to the structure already in place at Bangor Hydro.

I would like to thank Emera's Board of Directors for their support and vision over the past year. And to the 2,100 employees in the Emera family of companies– Thank you for your dedication and hard work which made 2006 a successful year for our company.

Why Invest in Emera?

As I said at the beginning, I am encouraged by the progress our company has made in 2006. My team and I are working hard to continue that progress in 2007. As we go forward, investors can continue to count on Emera for a dependable income stream, supported by our portfolio of assets that provide essential energy services. We will build our company by investing in businesses where our operational expertise gives us an advantage, in markets that are growing. We will be disciplined with our capital, seeking out niche opportunities to acquire assets at attractive prices, or where we can deliver new value. Where appropriate, we will work with partners to enhance our financial capacity, share risk and extend our reach. Our success will not only make Emera bigger, but stronger, diversifying our market risk and supporting our low risk investment profile.

Respectfully yours,

Christopher G. Huskilson
President and Chief Executive Officer

Chairman's message

Fellow Shareholders

On behalf of your Board of Directors, I am pleased to report positive results for 2006. In general terms, all of our operating divisions recorded increased earnings and improved profits. While we have work to accomplish in certain areas, I am encouraged by our progress and the overall outlook for our Company.

Complete details are available in various sections of this report, but I want to make specific reference to Nova Scotia Power's (NSPI) earnings, and to our continued growth in areas outside the Province of Nova Scotia. NSPI earned within its allowed range, worked successfully with its stakeholders to achieve the first-ever settlement of a rate application, and made substantial progress toward implementation of a fuel adjustment mechanism, a key priority for the Company.

Meanwhile, at Bangor Hydro, construction of the Northeast Reliability Interconnect is well underway, and on schedule for completion at the end of this year. I am also proud that Emera is involved in bringing Liquefied Natural Gas to the region, and as a New Brunswicker, I am pleased to see the Company working successfully with governments, business and communities to build support for the Brunswick Pipeline project.

These developments are a tribute to the hard work of our employees under the direction of our leadership team. On your behalf, I commend them for our achievements in 2006.

At the Board level, your Directors continued to focus on two key responsibilities in 2006 – strategy and governance. Indeed, we are making key changes to our companies' governance structures to enable better focus and execution of strategy at both the parent and operating subsidiary level.

Our objectives are straightforward. We want to ensure that our operating units have strong executive leadership, focused exclusively on running those businesses. We want to ensure we have governance structures that are built to meet the specific needs of each subsidiary, with appropriate blends of operational, regulatory, financial and stakeholder skill sets and perspectives. We want our subsidiaries' governance, particularly our regulated electric utilities, to be distinct from Emera, to support focus and transparency. Finally, we want to enable Emera's executive leadership and Board of Directors to focus its energy on growing our business to build value for our shareholders. Let me tell you more about our progress in 2006.

We established a separate Board of Directors for Nova Scotia Power Inc. This governance structure is similar to that of Bangor Hydro, and supports the operational focus and transparency that we consider of strategic importance to our regulated electric utilities. John McLennan is now Chairman of NSPI, and Ralph Tedesco was promoted to President and CEO of that Company. George Caines, Wes Armour and Irene d'Entremont are also NSPI Directors, and John, Chris Huskilson and I will continue to serve both the Emera and NSPI Boards. Early in 2007, NSPI welcomed Marie Rounding to its Board of Directors. Marie is the former President and CEO of the Canadian Gas Association, and she served six years as Chair and CEO of the Ontario Energy Board, the body that regulates that province's electricity and natural gas sectors. Her knowledge of the electricity industry and extensive regulatory expertise will be of great benefit to Nova Scotia Power.

Emera Inc. also has a new addition to its Board of Directors, Andrea Rosen. Andrea was formerly Vice-Chair of TD Bank Financial Group and President of TD Canada Trust. Her financial and banking expertise will be of particular benefit to Emera as we execute our growth agenda.

As I previously noted, a key goal of these governance changes is to enable Emera's Executive and Board of Directors to focus exclusively on defining and delivering on Emera's strategy for growth. That focus is producing results. Emera's investment to develop the Brunswick Pipeline is an exciting opportunity, and a good strategic fit for our Company. It is also important to our region, a key piece of infrastructure that will deliver natural gas from the Canaport™ Liquefied Natural Gas facility currently under construction in Saint John, New Brunswick, to markets in Canada and the United States. Our investment in early 2007 to acquire 19% of St. Lucia

Electricity Services is an exciting strategic step, which provides a vantage point on a potential new geography while maintaining an appropriate risk profile. On behalf of Directors and shareholders, I want to acknowledge Emera CEO Chris Huskilson for his strong and sure leadership in evolving and executing our strategy for growth.

We made other important enhancements to our governance program in 2006, in line with evolving best practices. Emera companies are committed to providing our employees with a work environment based on trust, respect and high ethical standards. We encourage an open atmosphere in which concerns can be brought up and dealt with. However, in rare situations, employees may be uncomfortable raising an issue yet it may well be those issues that are most important for the Company to be aware of. Accordingly, Emera established procedures for reporting irregularities (commonly known as a "Whistleblower Policy"), and introduced an anonymous and confidential reporting system for employees, *The Ethics Hotline*. Together, these policies and tools help employees to anonymously and confidentially report sensitive workplace information relating to many issues including financial reporting and accounting issues, fraud/theft, conflict of interest or other ethical matters.

Emera also enhanced its process for identifying and recruiting potential new Directors, updating required skills and experience profiles, and working with external consultants to explore and evaluate a broader pool of potential candidates.

In closing, I thank all of our Directors for their ongoing support, insight and guidance. I look forward to continuing to work together to advance our Company in 2007 and beyond.

Yours truly,

Derek Oland
Chairman of the Board of Directors

Management's discussion and analysis

As at February 16, 2007

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 2006 relative to 2005, and the full year 2006 relative to 2005 and to 2004; and its financial position at December 31, 2006 relative to 2005. Certain factors that may affect future operations are also discussed. Such comments will be affected by, and may involve, known and unknown risks and uncertainties that may cause the actual results of the company to be materially different from those expressed or implied. Those risks and uncertainties include, but are not limited to, weather, commodity prices, interest rates, foreign exchange, regulatory requirements and general economic conditions. 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 follows Canadian Generally Accepted Accounting Principles ("GAAP"). Emera's wholly-owned subsidiary, Nova Scotia Power Inc.'s accounting policies are subject to examination and approval by the Nova Scotia Utility and Review Board. Emera's wholly-owned subsidiary, Bangor Hydro-Electric Company's accounting policies are subject to examination and approval by the Maine Public Utilities Commission and the Federal Energy Regulatory Commission. The rate-regulated accounting policies of Nova Scotia Power and Bangor Hydro may differ from GAAP for non rate-regulated companies.

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**.

CONSOLIDATED FINANCIAL HIGHLIGHTS

	Three months ended December 31		Year ended December 31		
millions of dollars (except earnings per common share)	**2006**	2005	**2006**	2005	2004
Revenues	**$ 307.0**	$ 297.1	**$ 1,166.0**	$ 1,168.0	$ 1,134.2
Net earnings from continuing operations	**33.5**	37.7	**125.8**	122.1	127.6
Consolidated net earnings	**33.5**	37.7	**125.8**	121.2	129.8
Earnings per common share – basic					
Continued operations	**0.30**	0.34	**1.14**	1.12	1.18
Total	**0.30**	0.34	**1.14**	1.11	1.20
Earnings per common share – fully diluted					
Continued operations	**0.30**	0.34	**1.12**	1.10	1.14
Total	**0.30**	0.34	**1.12**	1.09	1.16
Cash dividends declared per share	**0.2225**	0.2225	**0.89**	0.89	0.88

	As at December 31		
	2006	2005	2004
Total assets	**$ 4,059.8**	$ 3,998.6	$ 3,949.2
Total long-term liabilities	**2,149.9**	2,126.0	2,118.8

Introduction and strategic overview

The core business of Emera is electricity. The company owns and operates two regulated electric utilities in northeastern North America. Both businesses operate as monopolies in their service territories, and together comprise approximately 95% of Emera's consolidated revenues:

- Nova Scotia Power Inc. ("NSPI") is an electricity generation, transmission and distribution company, providing service to the vast majority of the province of Nova Scotia. NSPI has $3 billion in assets, and 470,000 customers. NSPI is a cost of service utility. As such, regulated electricity rates are set to enable the company to recover all prudently incurred costs, with an opportunity to earn a prescribed return on equity. The company is regulated by the Nova Scotia Utility and Review Board ("UARB").
- Bangor Hydro-Electric Company ("BHE") is an electricity transmission and distribution company with $640 million of assets serving 115,000 customers in eastern Maine. BHE's transmission operations are regulated by the Federal Energy Regulatory Commission ("FERC"), and its distribution operations are regulated by the Maine Public Utilities Commission ("MPUC"). BHE is a cost of service utility, with an alternate rate plan ("ARP") for its distribution operations.

The success of Emera's electric utilities is integral to the creation of shareholder value, providing substantial earnings and cash flow to fund dividends and reinvestment. The essential nature of the services provided, the monopoly positions, and the regulated market structures means that NSPI and BHE can generally be expected to produce stable earnings streams within regulated ranges. Nova Scotia and Maine are mature electricity markets, with annual demand growth of approximately 2%. Accordingly, Emera must look beyond its existing regulated electricity business to supplement organic growth.

Emera's objective is to deliver annual consolidated earnings growth of 4%–6%, and build and diversify its earnings base such that eventually 35% of consolidated net earnings are derived from investments other than Nova Scotia Power. Emera's plan for growth leverages its core strength in the electricity business. Emera will pursue both acquisitions and greenfield development opportunities in regulated electricity transmission and distribution and low risk generation. Emera will also capitalize on opportunities in related energy infrastructure businesses appropriate to its risk profile, where its development, commercial and operational skills are needed.

Recent investments include:

- Bear Swamp, a 600 megawatt ("MW") pumped storage Hydro-Electric generating facility in northern Massachusetts, acquired in a joint venture with Brookfield Power in 2005;
- Brunswick Pipeline, a proposed $350 million greenfield pipeline project under development that will deliver natural gas from the planned Canaport™ Liquefied Natural Gas ("LNG") import terminal near Saint John, New Brunswick to markets in Canada and the US northeast. The 145 kilometer Brunswick Pipeline will travel through southwest New Brunswick and connect with the Maritimes and Northeast Pipeline ("M&NP") at the Canada/US border near Baileyville, Maine. Emera has been an investor in M&NP since its inception in 1999.

  Canaport™ LNG is a partnership of Repsol YPF, S.A. ("Repsol") and Irving Oil Limited. Emera has negotiated a 25 year send or pay toll agreement with Repsol to transport natural gas through the Brunswick Pipeline. Emera has also negotiated agreements with its M&NP partner, Spectra Energy Corp., formerly Duke Energy ("Spectra"), an affiliate of which will assist Emera in the Brunswick Pipeline permitting process, and construct and operate the pipeline on Emera's behalf.

  Emera expects to finance the investment with internally generated cash flow and debt. The investment is forecast to provide a return on project equity of 11%–14%.

  The project requires National Energy Board ("NEB") approval. NEB hearings were completed in November 2006, with a decision expected in Q2 2007. Assuming approval is granted, the pipeline is expected to be in service by the end of 2008.

  Emera's net cash requirements related to Brunswick Pipeline are expected to be $65.0 million for 2007.

- St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated electric utility serving more than 50,000 customers on the Caribbean island of St. Lucia. Emera acquired a 19% equity interest in Lucelec for US $22 million in January 2007.

  Lucelec has an exclusive license to generate, transmit and distribute electricity on the island to 2045. The utility has 66 MW of generating capacity, primarily oil fired, and 800 kilometers of electricity transmission and distribution assets. Lucelec is a cost of service utility, with a minimum rate of return of 10% on a 50% equity base. Emera financed the acquisition with existing credit facilities. Lucelec is expected to add approximately $1 to $2 million to Emera's annual consolidated net earnings.

  Emera's strategy recognizes that the Caribbean market has attractive growth prospects and opportunities for the company to deploy its operational expertise. This modest investment in Lucelec provides Emera with a low risk vehicle to assess whether there is broader business potential for the company in the region, and at the same time, provides immediately accretive and attractive returns.

CONSOLIDATED NET EARNINGS HISTORY

millions of dollars

2006	2005	2004	2003	2002	2001
$ 125.8	$ 121.2	$ 129.8	$ 129.2	$ 83.6	$ 114.2

EARNINGS PER SHARE HISTORY

dollars

2006	2005	2004	2003	2002	2001
$ 1.14	$ 1.11	$ 1.20	$ 1.20	$ 0.85	$ 1.20

STRUCTURE OF MD&A

This MD&A has been prepared in accordance with the Canadian Securities Administrators National Instrument 51–102 Management's Discussion & Analysis.

This Management's Discussion and Analysis begins with an overview of consolidated results; then presents information on the company's two primary subsidiaries, NSPI and BHE. All other operations, including the Maritimes & Northeast Pipeline, Emera Energy Services, Bear Swamp, and corporate activities are grouped and discussed as "Other". Significant changes in the consolidated balance sheets, outstanding share data, liquidity and capital resources, financial and commodity instruments, transactions with related parties, disclosure and internal controls, critical accounting estimates, changes in accounting policies, dividend policy and payout ratios, business risks and enterprise risk management, and selected quarterly trend information are presented on a consolidated basis.

EMERA CONSOLIDATED

Summary Consolidated Income Statement

millions of dollars (except earnings per common share)	Three months ended December 31 2006	Three months ended December 31 2005	Year ended December 31 2006	Year ended December 31 2005	Year ended December 31 2004
Electric revenue	**$ 301.6**	$ 287.3	**$ 1,132.0**	$ 1,125.9	$ 1,095.7
Other	**5.4**	9.8	**34.0**	42.1	38.5
	307.0	297.1	**1,166.0**	1,168.0	1,134.2
Fuel for generation and purchased power	**102.3**	96.7	**347.7**	432.0	350.0
Operating, maintenance and general	**65.0**	61.9	**255.6**	248.2	245.2
Provincial, state and municipal taxes	**11.7**	11.8	**48.0**	48.4	46.3
Provincial tax deferral	**–**	0.4	**–**	(4.5)	–
Depreciation	**36.9**	34.2	**145.2**	136.1	131.2
Regulatory amortization	**6.2**	2.9	**22.8**	19.4	26.1
Other	**(3.3)**	(2.7)	**(10.7)**	(10.9)	(10.2)
Earnings before interest and income taxes	**88.2**	91.9	**357.4**	299.3	345.6
Interest	**34.2**	38.4	**127.1**	117.4	126.8
Amortization of defeasance costs	**3.2**	3.3	**12.7**	13.2	15.1
Other income	**(8.9)**	(8.0)	**(8.9)**	(8.0)	–
Earnings before income taxes	**59.7**	58.2	**226.5**	176.7	203.7
Income taxes	**22.9**	19.0	**87.4**	53.5	62.7
Income taxes deferral	**–**	(1.8)	**–**	(12.2)	–
Net earnings before non-controlling interest	**36.8**	41.0	**139.1**	135.4	141.0
Non-controlling interest	**3.3**	3.3	**13.3**	13.3	13.4
Net earnings from continuing operations	**33.5**	37.7	**125.8**	122.1	127.6
(Loss) earnings from discontinued operations, net of tax	**–**	–	**–**	(0.9)	2.2
Net earnings applicable to common shares	**$ 33.5**	$ 37.7	**$ 125.8**	$ 121.2	$ 129.8
Earnings per common share – basic					
Continuing operations	**$ 0.30**	$ 0.34	**$ 1.14**	$ 1.12	$ 1.18
Discontinued operations	**–**	–	**–**	(0.01)	0.02
	$ 0.30	$ 0.34	**$ 1.14**	$ 1.11	$ 1.20
Earnings per common share – diluted					
Continuing operations	**$ 0.30**	$ 0.34	**$ 1.12**	$ 1.10	$ 1.14
Discontinued operations	**–**	–	**–**	(0.01)	0.02
	$ 0.30	$ 0.34	**$ 1.12**	$ 1.09	$ 1.16

Operating Unit Contributions

millions of dollars	Three months ended December 31 2006	Three months ended December 31 2005	Year ended December 31 2006	Year ended December 31 2005	Year ended December 31 2004
Nova Scotia Power	**$ 29.9**	$ 34.0	**$ 104.3**	$ 91.2	$ 107.3
Bangor Hydro-Electric	**5.3**	4.0	**16.8**	14.9	18.5
Other, including corporate costs	**(1.7)**	(0.3)	**4.7**	15.1	4.0
Consolidated net earnings	**$ 33.5**	$ 37.7	**$ 125.8**	$ 121.2	$ 129.8

REVIEW OF 2006

Emera Inc.'s consolidated earnings decreased $4.2 million to $33.5 million in Q4 2006 compared to $37.7 million for the same period in 2005. Emera's annual consolidated earnings were $125.8 million in 2006 compared to $121.2 million in 2005 and $129.8 million in 2004. 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 – 2004		**$ 129.8**
Increased electric revenue in NSPI due to an electricity price increase, partially offset by a 36 GWh decrease in sales volume		28.1
Increased fuel expense in NSPI due to higher commodity prices, and changes in generation mix partially offset by increased hydro production and natural gas resale margin		(70.7)
Increased operating expenses in NSPI reflecting increased planned plant maintenance, storm-related costs and regulatory costs		(11.3)
Net payment from a gas supplier in NSPI		8.0
Decreased income taxes in NSPI resulting from lower earnings		13.7
Deferral of Q1 2005 taxes in NSPI		16.7
Addition of Bear Swamp hydro-electric facility earnings before interest & taxes		4.2
Foreign exchange gains in Other reflecting an adjustment to refine prior years' foreign exchange		5.2
All other		(2.5)
Consolidated net earnings – 2005	**$ 37.7**	**$ 121.2**
Increased electric revenue in NSPI due to electricity price increases and increased export sales partially offset by reduced industrial sales volume and warmer weather year over year	15.0	12.9
Decreased fuel expense year over year in NSPI due to reduced load and increased natural gas sales margin partially offset by higher commodity prices and increased export sales; quarter over quarter includes a favourable adjustment in Q4 2005 to reflect finalization of pricing terms of NSPI's natural gas supply contract	(8.2)	81.0
Increased operating expenses in NSPI mainly due to pension costs	(2.7)	(13.7)
Increased depreciation and regulatory amortization in NSPI	(4.4)	(10.7)
Increased interest expense in NSPI due to higher long-term debt balances and foreign exchange losses on USD contracts	(1.6)	(7.5)
Insurance proceeds received for a supply interruption claim in NSPI	8.9	8.9
Net payment from a gas supplier in NSPI in 2005	(8.0)	(8.0)
Increased taxes in NSPI primarily due to higher taxable income	(2.0)	(34.8)
Deferral of Q1 2005 taxes in NSPI	(1.4)	(16.7)
Increased overheads capitalized in BHE primarily as a result of capital expenditures on the Northeast Reliability Interconnect transmission project	3.2	6.3
Decreased earnings before interest and taxes in Emera Energy Services and Bear Swamp	(1.8)	(6.0)
Foreign exchange gains in Other recognized in 2005 reflecting an adjustment to refine prior years' foreign exchange	–	(5.2)
All other	(1.2)	(1.9)
Consolidated net earnings – 2006	**$ 33.5**	**$ 125.8**

Q4 basic earnings per share were $0.30 in 2006 compared to $0.34 in 2005; and $1.14 for the full year 2006 compared to $1.11 in 2005 and $1.20 in 2004.

SIGNIFICANT ITEMS

2006

In late 2005 a number of Nova Scotia Power's petroleum coke suppliers were unable to supply fuel due to hurricanes in the Gulf of Mexico, which seriously affected their operations. As a result, Nova Scotia Power incurred additional costs for replacement fuel and other expenses, which were included in Q4 2005 fuel expense. NSPI filed a claim with its insurers to recover applicable costs. In Q4 2006, Nova Scotia Power received $8.9 million ($5.5 million after-tax) in settlement of this claim.

2005

Natural Gas Supply Contract

In Q4 2005, Nova Scotia Power reached an agreement with its supplier on pricing for natural gas under an existing long-term natural gas purchase agreement. The contract was subject to a price re-determination as of November 1, 2004. Throughout most of 2005, while the new pricing was under discussion, NSPI recorded its gas purchases at its best estimate of the new contract price. The pricing ultimately agreed to was more favourable than NSPI's estimate. This resulted in a $23.8 million ($14.7 million after-tax) adjustment to fuel expense for 2005, all of which was recorded in Q4 2005. In addition, in a separate agreement, NSPI was provided a net payment of $8.0 million ($5.0 million after-tax) by its gas supplier, which was recorded as other income in Q4 2005.

Deferral of Q1 Income and Capital Taxes

The UARB agreed to allow Nova Scotia Power to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. In 2005, NSPI deferred $16.7 million, consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes reflecting increases in these taxes since rates had last been set in 2002.

2004

There were no significant items in 2004.

NOVA SCOTIA POWER INC.

OVERVIEW

NSPI is the primary electricity supplier in Nova Scotia, providing over 95% of electricity generation, transmission and distribution in the province. The company owns 2,293 megawatts ("MW") of generating capacity. Approximately 55% is coal-fired; oil and natural gas together comprise another 30% of capacity; and hydro and wind production provide the remainder. NSPI has 86 MW of renewable energy, substantially wind energy, under contract with independent power producers. 80 MW are in service and the remainder is expected to be in operation in the next 12 months. NSPI also owns approximately 5,000 kilometers of transmission facilities, and 25,000 kilometers of distribution facilities. The company has a workforce of approximately 1,700 people.

NSPI is a public utility as defined in the Public Utilities Act (Nova Scotia) 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 an annual rate review process, but rather participates in hearings from time to time at the company's or the regulator's request.

Nova Scotia Power 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 allowed return on equity range is 9.3% to 9.8%, on a maximum allowed common equity component of 40% of total capitalization. Rates were last set at a 9.55% return on equity, with a common equity component of 37.5%.

2007 Rate Decision

In October 2006, NSPI filed an application for an average rate increase of 7.5%. The proposed increase was to cover increased fuel costs and costs previously approved but deferred for future recovery by the UARB.

In January 2007 NSPI and most parties to the application presented a settlement agreement to the UARB, which provided for an average increase in electricity rates of 3.8% effective April 1, 2007. The decrease in the revenue requirement compared to the original application primarily reflects a reduction in the company's forecast fuel costs and the postponement of the phase-in of higher depreciation rates. Other key elements of the original application were unchanged in the settlement, including rate base, return on equity (maintained at 9.3%–9.8%), operating, maintenance and general expenditures, and recovery of previously deferred and paid taxes.

A central provision of the settlement is an agreement in principle that the UARB should establish a fuel adjustment mechanism ("FAM") for Nova Scotia Power to ensure actual fuel costs are recovered from customers.

The settlement was approved by the regulator on February 5, 2007. Hearings on the implementation of a FAM are expected in mid-2007.

2006 Rate Decision

The Nova Scotia Utility and Review Board granted NSPI an average rate increase of approximately 8.7% effective March 10, 2006. The UARB noted improvements NSPI had made in fuel procurement, but determined that a previous finding related to 2002 and 2003 fuel procurement carried over into 2006, resulting in a $15.7 million disallowance for 2006. The UARB noted that this would be the final disallowance related to this issue.

2005 Rate Decision

On March 31, 2005, the UARB granted NSPI an average rate increase of approximately 5.3%, effective April 1, 2005. In the 2005 decision, the UARB expressed dissatisfaction with certain past fuel procurement practices, resulting in a disallowance of $18 million of NSPI's forecasted 2005 fuel costs.

REVIEW OF 2006

NSPI Net Earnings

millions of dollars (except earnings per common share)	Three months ended December 31		Year ended December 31		
	2006	2005	**2006**	2005	2004
Electric revenue	**$ 257.9**	$ 243.0	**$ 967.9**	$ 955.0	$ 926.9
Fuel for generation and purchased power	**87.7**	79.5	**292.8**	373.8	303.1
Operating, maintenance and general	**51.5**	48.8	**202.5**	188.8	177.5
Provincial grants and taxes	**10.1**	10.2	**40.3**	40.4	39.5
Provincial grants and taxes deferral	**–**	0.4	**–**	(4.5)	–
Depreciation	**32.1**	30.1	**127.8**	119.5	116.0
Regulatory amortization	**3.9**	1.5	**8.6**	6.2	6.2
Other	**(2.9)**	(2.6)	**(11.2)**	(10.1)	(10.4)
Earnings before interest and income taxes	**75.5**	75.1	**307.1**	240.9	295.0
Interest	**27.4**	25.8	**105.4**	97.9	100.1
Amortization of defeasance costs	**3.2**	3.3	**12.7**	13.2	15.1
Other income	**(8.9)**	(8.0)	**(8.9)**	(8.0)	–
Earnings before income taxes	**53.8**	54.0	**197.9**	137.8	179.8
Income taxes	**20.5**	18.5	**80.3**	45.5	59.2
Income taxes deferral	**–**	(1.8)	**–**	(12.2)	–
Earnings before preferred dividends	**33.3**	37.3	**117.6**	104.5	120.6
Preferred dividends	**3.4**	3.3	**13.3**	13.3	13.3
Contribution to consolidated net earnings	**$ 29.9**	$ 34.0	**$ 104.3**	$ 91.2	$ 107.3
Contribution to consolidated earnings per common share	**$ 0.27**	$ 0.30	**$ 0.94**	$ 0.83	$ 0.99

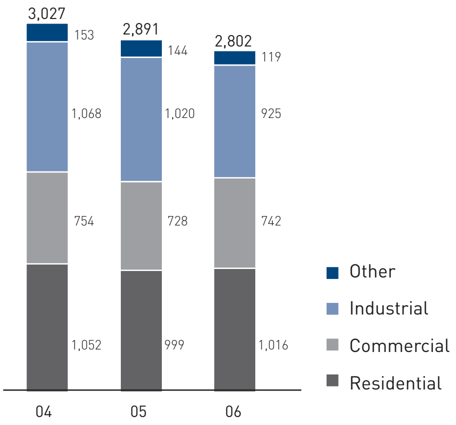
NSPI's contribution to consolidated net earnings decreased $4.1 million to $29.9 million in Q4 2006, compared to $34.0 million in Q4 2005. Annual contribution to consolidated net earnings increased $13.1 million to $104.3 million in 2006 compared to $91.2 million in 2005, and was $107.3 million in 2004. 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 – 2004		**$ 107.3**
Increased electric revenue due to an electricity price increase, partially offset by a 36 GWh decrease in sales volume		28.1
Increased fuel expense due to higher commodity prices, and changes in generation mix partially offset by increased hydro production and natural gas resale margin		(70.7)
Increased operating expenses reflecting increased planned plant maintenance, storm-related costs, and regulatory costs		(11.3)
Net payment from a gas supplier		8.0
Decreased income taxes resulting from lower earnings		13.7
Deferral of Q1 2005 taxes		16.7
All other		(0.6)
Contribution to consolidated net earnings – 2005	**$ 34.0**	**$ 91.2**
Increased electric revenue due to electricity price increases and increased export sales	15.3	87.1
Decreased electric revenue due to reduced industrial sales volume and warmer weather year over year	(0.3)	(74.2)
Decreased fuel expense year over year due to reduced load and increased natural gas sales margin partially offset by higher commodity prices and increased export sales; quarter over quarter includes a favourable adjustment in Q4 2005 to reflect finalization of pricing terms of NSPI's natural gas supply contract	(8.2)	81.0
Increased operating expenses mainly due to pension costs	(2.7)	(13.7)
Increased depreciation and regulatory amortization	(4.4)	(10.7)
Increased interest expense due to higher long-term debt balances and foreign exchange losses on USD contracts	(1.6)	(7.5)
Insurance proceeds received for a supply interruption claim	8.9	8.9
Net payment from a gas supplier in 2005	(8.0)	(8.0)
Increased taxes primarily due to higher taxable income	(2.0)	(34.8)
Deferral of Q1 2005 taxes	(1.4)	(16.7)
All other	0.3	1.7
Contribution to consolidated net earnings – 2006	**$ 29.9**	**$ 104.3**

ELECTRIC REVENUE

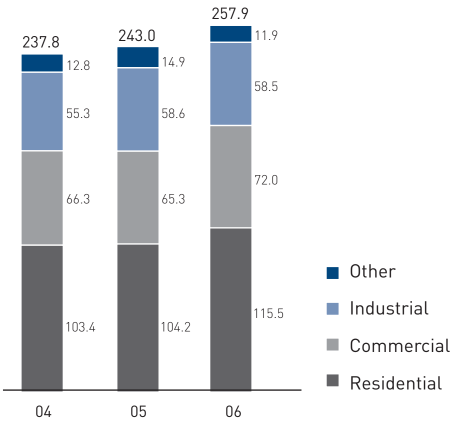
Q4 Electric Sales Volume

Gigawatt hours ("GWh")



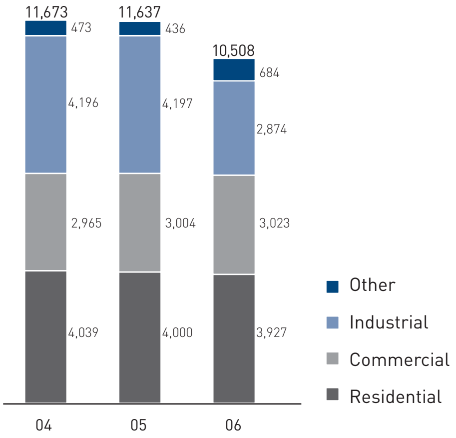
Q4 Electric Sales Revenues

millions of dollars



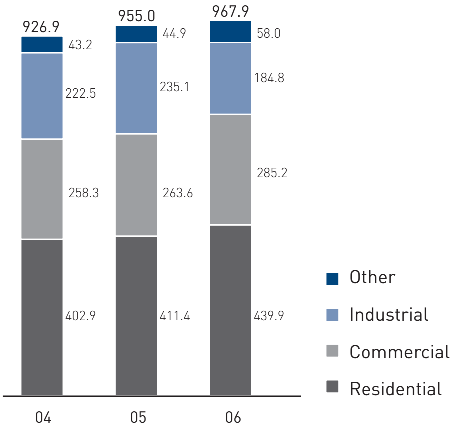
YTD Electric Sales Volume

GWh



YTD Electric Sales Revenues

millions of dollars



Q4 Average Revenue per Megawatt hour ("MWh")

		2006		2005		2004
Dollars per MWh	**$**	**92**	$	84	$	79

YTD Average Revenue per MWh

		2006		2005		2004
Dollars per MWh	**$**	**92**	$	82	$	79

Electric sales volume is primarily driven by general economic conditions, population and weather. Electricity pricing in Nova Scotia is regulated and therefore only changes when new regulatory decisions are implemented. The exceptions are annually adjusted rates, subscribed to by certain larger industrial customers, and export sales, which in recent years comprised less than 2% of NSPI sales volume and are priced at market. 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 everything from small retail operations to large office and commercial complexes, and the province's universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other consists of export sales, sales to municipal electric utilities and revenues from street lighting.

Electric revenues increased by $14.9 million to $257.9 million in Q4 2006 from $243.0 million for the same period in 2005. Revenue increases are substantially due to the 8.7% rate increase effective March 10, 2006.

For the year ended December 31, 2006, electric revenues increased $12.9 million to $967.9 million in comparison to $955.0 million in 2005. The impact of the rate increase noted above and increased export sales, was partially offset by the temporary shutdown of the large industrial customer for much of 2006, and warmer weather year over year.

For the year ended December 31, 2005, electric revenues increased $28.1 million, to $955.0 million from $926.9 million in 2004 substantially due to a 5.3% rate increase effective April 1, 2005. 2005 sales volumes were slightly lower than 2004, reflecting warmer weather and the temporary shutdown of the large customer for a portion of December 2005.

The increase in average revenue per MWh in the quarter and year to date reflects the rate increases noted above, and a change in sales mix, specifically a reduction in industrial sales.

FUEL FOR GENERATION AND PURCHASED POWER

Capacity

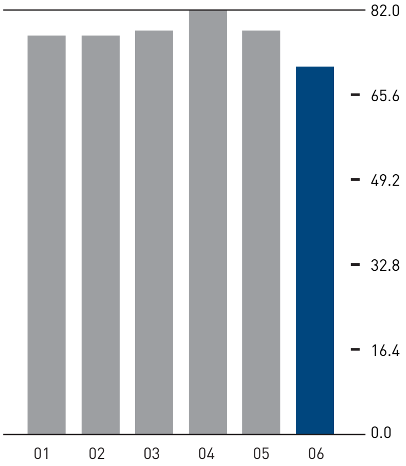
To ensure reliability of service, NSPI maintains a generating capacity greater than firm peak demand. The total company-owned generation capacity is 2,293 MW, which is supplemented by 80 MW in service contracted with independent power producers. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area, and the Northeast Power Coordinating Council.

Management of capacity/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. NSPI's daily load is highest in the early evening; its seasonal load is highest through the winter months. Summer cooling load is not a significant factor. Maximizing capacity utilization has a positive effect on earnings, and helps defer significant 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 continues to maintain unplanned outage rates below 3%.
- Moving demand from peak to non-peak periods – NSPI encourages customers to move some electricity demand from high cost to lower cost periods by offering customers various pricing alternatives. NSPI controls over 300 MW of interruptible electric load; over 250 MW is supplied under real time or time of day rates.
- Export sales – Increasing export sales when margins are satisfactory allows excess capacity to be sold when not required in the province. NSPI operates a 24-hour marketing desk to optimize commercial opportunities.

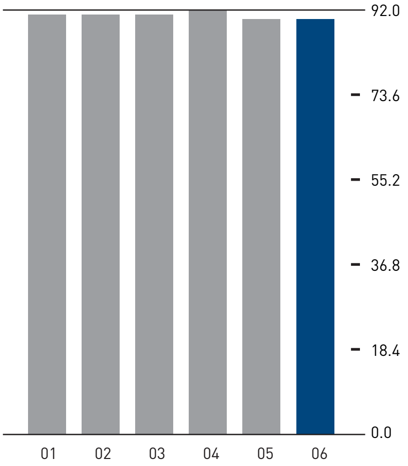
NSPI Thermal Capacity Utilization

(percent)



NSPI Generating Capacity Availability

(percent)



NSPI THERMAL CAPACITY UTILIZATION

NSPI's generating capacity utilization was 71% in 2006 compared to 78% in 2005. The Net System Requirement was reduced in 2006 due to NSPI's largest customer not operating for most of the year, and warmer weather year over year, reducing the home heating load.

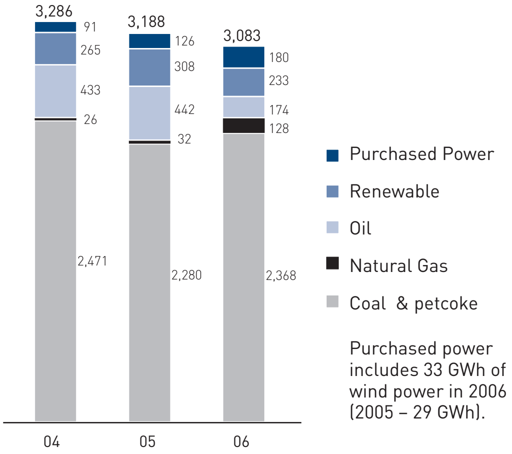
NSPI GENERATING CAPACITY AVAILABILITY

NSPI facilities continue to rank among the best in Canada on capacity related performance indicators. In the most recent Canadian Electrical Association rankings, NSPI units hold five of the top ten positions in the country. The company's Trenton 6 unit ranked first.

FUEL EXPENSE

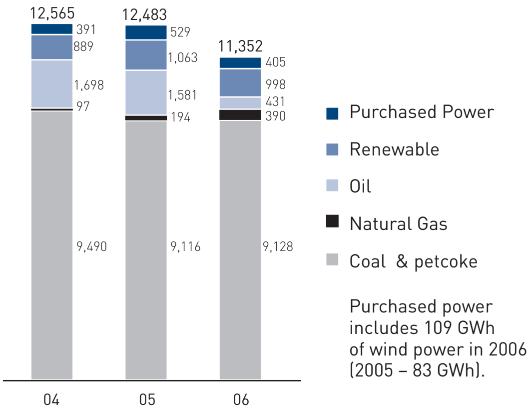
Q4 Production Volume

GWh



YTD Production Volume

GWh



Q4 Average Unit Fuel Costs

		2006		2005		2004
Dollars per MWh	**$**	**28**	$	25	$	26

YTD Average Unit Fuel Costs

		2006		2005		2004
Dollars per MWh	**$**	**26**	$	30	$	24

Coal is NSPI's dominant fuel source, supplying approximately 58% of the company's annual generation. Petroleum coke ("petcoke") fuels approximately 23% of generation. These solid fuels have the lowest per unit fuel cost, after hydro and wind production, which have no fuel cost component. Oil and natural gas are next, depending on the relative pricing of each. Purchased power is generally the most expensive option. 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. Accordingly, in 2006, the reduction in industrial load resulted in a decrease in oil fired production.

The Q4 average unit fuel costs are higher in 2006 due to a favourable adjustment in Q4 2005 to reflect finalization of pricing terms of the natural gas supply contract. The year to date average unit fuel costs have decreased in 2006 mainly due to higher natural gas margins, and NSPI's reduced use of higher priced fuels because of reduced load.

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 Risk and Enterprise Risk Management section.

For the three months ended December 31, 2006, fuel for generation and purchased power increased $8.2 million to $87.7 million, compared to $79.5 million in Q4 2005. For the year ended December 31, 2006, fuel for generation and purchased power decreased $81.0 million to $292.8 million compared to $373.8 million in 2005 and $303.1 million in 2004. 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 – 2004		**$ 303.1**
Commodity pricing increase		91.1
Higher net proceeds from resale of natural gas		(13.6)
Changes in generation mix		12.2
Increase in hydro production volumes		(11.7)
All other		(7.3)
Fuel for generation and purchased power – 2005	**$ 79.5**	**$ 373.8**
Decreased load due to the temporary shutdown of a large industrial customer and warmer weather	(14.5)	(79.6)
Increased net proceeds from the resale of natural gas	(11.2)	(23.2)
Commodity pricing increase	5.7	18.8
Decreased hydro production	3.7	2.2
Increased fuel expense due to favourable adjustment in Q4 2005 to reflect finalization of pricing terms of natural gas supply contract	23.8	–
All other	0.7	0.8
Fuel for generation and purchased power – 2006	**$ 87.7**	**$ 292.8**

In Q4 2005, Nova Scotia Power reached an agreement with its supplier on pricing for natural gas under an existing long-term natural gas purchase agreement. The contract was subject to a price re-determination as of November 1, 2004. Throughout most of 2005, while the new pricing was under discussion, NSPI recorded its gas purchases at its best estimate of the new contract price. The pricing ultimately agreed to was more favourable than NSPI's estimate. This resulted in a $23.8 million ($14.7 million after-tax) adjustment to fuel expense for 2005, all of which was recorded in Q4 2005. In addition, in a separate agreement, NSPI was provided a net payment of $8.0 million ($5.0 million after-tax) by its gas supplier, which was recorded as other income in Q4 2005.

OPERATING, MAINTENANCE AND GENERAL EXPENSES

NSPI's operating, maintenance and general expenses increased $2.7 million, to $51.5 million in Q4 2006 compared to $48.8 million in Q4 2005, primarily due to higher pension costs. For the year ended December 31, 2006, NSPI's operating, maintenance and general expenses increased $13.7 million, to $202.5 million compared to $188.8 million in 2005, primarily for the same reason.

Operating, maintenance and general expenses increased $11.3 million, to $188.8 million in 2005 from $177.5 million in 2004, due to increased planned plant maintenance, storm-related costs and regulatory costs.

PROVINCIAL GRANTS AND TAXES

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

In Q1 2005, the UARB agreed to allow NSPI to defer taxes not included in rates for the period from January 1, 2005 until April 1, 2005, the date when new rates became effective. In its February 5, 2007 decision, the UARB approved amortization of the deferred amount over an eight-year period, beginning April 1, 2007.

DEPRECIATION

NSPI's depreciation expense increased $2.0 million in Q4 2006, to $32.1 million compared to $30.1 million in Q4 2005, primarily due to the scheduled phase-in of increased depreciation rates as approved by the UARB.

For the year ended December 31, 2006 depreciation expense increased $8.3 million, to $127.8 million compared to $119.5 million in 2005, for the reason noted above. The 2005 amount is $3.5 million higher than 2004, reflecting increased plant-in-service.

In its February 5, 2007 decision, the UARB postponed the scheduled year-three phase-in of increased depreciation rates until the next rate application.

REGULATORY AMORTIZATION

The Glace Bay generating station has been returned to an industrial greenfield site, and is being amortized at a minimum annual rate of $6.2 million. In 2006 NSPI amortized $8.6 million (2005 – $6.2 million). The amount remaining to be written off is $5.1 million.

INTEREST

Interest expense increased $1.6 million, to $27.4 million in Q4 2006 compared to $25.8 million in Q4 2005, primarily due to a gain recognized in 2005 on an interest rate derivative.

For the year ended December 31, 2006, interest expense increased $7.5 million, to $105.4 million compared to $97.9 million in 2005 due to the issuance in November 2005 of a $150 million 5.67% medium-term note which partially refinanced short-term debt, and foreign exchange losses.

For the year ended December 31, 2005, interest expense decreased $2.2 million, to $97.9 million from $100.1 million for 2004 largely due to the refinancing in May 2005 of a $100 million 8.38% medium-term note with a $100 million 4.22% medium-term note.

The company manages exposure to interest rate risk through a combination of fixed and floating borrowing, and hedging. Interest rate caps are the principal instrument used to hedge interest rate risk.

OTHER INCOME

In Q4 2006, Nova Scotia Power received an $8.9 million insurance settlement on a petcoke supply interruption claim.

In Q4 2005, Nova Scotia Power received a net payment of $8.0 million from a natural gas supplier as part of renegotiation of contractual matters.

INCOME TAXES

In accordance with ratemaking regulations established by the UARB, NSPI uses the taxes-payable method of accounting for income taxes.

NSPI is subject to provincial capital tax (0.263%), corporate income tax (38.12%) and Part VI.1 tax relating to preferred dividends (40%).

In addition to the deferral of provincial grants and taxes referred to above, in Q1 2005 NSPI deferred a portion of federal capital taxes and income taxes, reflecting increases in these taxes since rates were last set in 2002. In its February 5, 2007 decision, the UARB approved amortization of the deferred amount over an eight-year period, beginning April 1, 2007.

NSPI has a $147.1 million regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers. In its February 5, 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

OUTLOOK

Electricity sales volume (load) is expected to be higher in 2007 than in 2006 because the large industrial customer that was not operating for much of 2006 has restarted operations. Electric sales revenue will also increase due to an approved 3.8% electricity price increase effective April 1, 2007.

Fuel costs are expected to increase primarily due to the expected increase in sales volume noted above, and higher commodity prices, particularly oil.

NSPI will begin recovery of previously deferred and paid taxes on April 1, 2007, which will be reflected in regulatory amortization. Other costs of NSPI are generally expected to remain consistent with 2006 levels.

DEBT MANAGEMENT

There were no new long-term debt issuances in 2006.

In Q4 2005, NSPI issued a $150 million medium-term note at a coupon rate of 5.67% maturing November 14, 2035. Proceeds were used to pay down short-term debt.

Earlier in 2005, NSPI issued a $100 million medium-term note at a coupon rate of 4.22% maturing May 17, 2010. The proceeds were used to refinance $100 million 8.38% medium-term notes that matured on that date.

The weighted average coupon rate on NSPI's outstanding medium-term and debenture notes at December 31, 2006, was 6.86% (2005 – 6.83%). Approximately 38% of the debt matures over the next ten years; 58% matures between 2017 and 2036; and $50 million, or 4%, matures in 2097. The quoted market-weighted average interest rate for the same or similar issues of the same remaining maturities was 5.10% as of December 31, 2006 (2005 – 4.96%).

NSPI has established the following available credit facilities:

Short-term millions of dollars	Maturity	Maximum amount
Commercial paper, with 100% backup line of credit	1 Year Revolving	$ 400.0
Operating credit facility	3 Year Revolving	$ 100.0

In June 2006, Standard & Poor's ("S&P") rating agency lowered the corporate and senior unsecured debt credit ratings of Nova Scotia Power to BBB/Stable Outlook from BBB+/Negative Outlook. The ratings on NSPI's preferred shares were lowered to P-3(high) from P-2(low). NSPI's commercial paper program rating remained unchanged at A2. S&P cited concerns related to the recovery of fuel-related expenses under the current regulatory framework in Nova Scotia; an evolving fuel procurement strategy; and upcoming challenges related to the approval, financing and execution of several proposed capital projects as reasons for the change. In October 2005, Moody's rating agency revised NSPI's rating outlook to negative from stable, citing Nova Scotia Power fuel cost recovery concerns and regulatory uncertainty. The change could have cost implications for Nova Scotia Power as the company re-finances existing debt in future years, issues new capital, or enters into new fuel procurement arrangements. The ratings issued by Dominion Bond Rating Service ("DBRS") are unchanged.

NSPI has the following available credit ratings:

	DBRS		S&P		Moody's	
	2006	2005	**2006**	2005	**2006**	2005
Corporate	**A (low)**	A (low)	**BBB**	BBB +	**Baa1**	N/A
Senior unsecured debt	**A (low)**	A (low)	**BBB**	BBB +	**Baa1**	Baa1
Preferred stock	**Pfd-2 (low)**	Pfd-2 (low)	**P-3 (high)**	P-2 (low)	**N/A**	N/A
Commercial paper	**R-1 (low)**	R-1 (low)	**A-2 (Cdn)**	A-2 (Cdn)	**P-2 (Baa)**	P-2 (Baa)

OUTLOOK

Based on the company's available credit and credit ratings, and past experience, NSPI expects to have access to capital when needed.

BANGOR HYDRO-ELECTRIC COMPANY

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

OVERVIEW

Bangor Hydro is the second largest electric utility in Maine.

BHE's core business is the transmission and distribution ("T&D") of electricity. Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the commodity that is delivered through the BHE T&D network. BHE owns and operates approximately 950 kilometers of transmission facilities, and 7,900 kilometers of distribution facilities. BHE is currently investing approximately $120 million in the Northeast Reliability Interconnect ("NRI"), an international electricity transmission line connecting New Brunswick to Maine, which is expected to be in service in late 2007. BHE has a workforce of approximately 240 people.

In addition to T&D assets, BHE 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. BHE's net regulatory assets primarily include the costs associated with the buy-out/restructuring of above-market power purchase contracts; 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 $63 million at December 31, 2006, or 11% of BHE's net asset base.

Approximately 55% of BHE's electric rate represents distribution service, 15% relates to stranded cost recoveries, and 30% to transmission service. The rates for each element are established in distinct regulatory proceedings. BHE'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").

BHE's distribution service operates under an Alternate Rate Plan ("ARP"), which provides for an earnings band of 5% to 17% return on equity on distribution operations, with rates set at the midpoint of 11%. There is a 50/50 sharing mechanism between the company and customers outside of the earnings band. The ARP also includes performance standards and provides for average annual reductions in distribution rates of approximately 2.5% for five years, to 2007.

BHE's stranded cost rates provide for an allowed return on equity of 10% on the related asset base for the three-year period ending February 29, 2008.

In Q4 2006 BHE announced its intention to file a request for changes in both its distribution rates and stranded cost rates, to go into effect Q1 2008. Bangor Hydro's filing requests an increase in distribution rates as a result of shrinkage in overall load. This increase is substantially offset by the requested reduction in stranded cost rates such that the net impact on electric rates is minimal.

Transmission rates are set by the FERC annually on July 1, based on the prior year's revenue requirement. The allowed ROE for transmission operations was 11.25% through October 31, 2006. As a result of a recent FERC ruling, the allowed ROE on transmission assets ranges from 10.9% for low voltage transmission up to 12.4% for high voltage transmission developed as a result of the regional system plan, which includes the NRI project.

REVIEW OF 2006

BHE Net Earnings

	Three months ended December 31		Year ended December 31		
millions of dollars (except earnings per common share)	**2006**	2005	**2006**	2005	2004
T&D revenues	**$ 25.5**	$ 25.9	**$ 101.8**	$ 105.5	$ 116.4
Resale of purchased power	**3.7**	4.0	**15.2**	13.6	10.6
Total electric revenue	**29.2**	29.9	**117.0**	119.1	127.0
Fuel for generation and purchased power	**8.2**	9.7	**31.4**	33.6	35.0
Operating, maintenance and general	**7.0**	7.7	**27.1**	31.2	31.7
Property taxes	**1.0**	0.8	**5.0**	4.9	4.8
Depreciation	**3.2**	3.2	**12.9**	12.4	10.9
Regulatory amortization	**2.0**	1.1	**12.6**	10.8	15.2
Other	**(2.1)**	(0.8)	**(5.9)**	(3.9)	(3.3)
Earnings before interest and income taxes	**9.9**	8.2	**33.9**	30.1	32.7
Interest	**2.7**	2.6	**10.3**	10.0	10.3
Earnings before income taxes	**7.2**	5.6	**23.6**	20.1	22.4
Income taxes	**2.6**	2.2	**8.8**	7.8	8.0
Contribution to consolidated net earnings – US $	**$ 4.6**	$ 3.4	**$ 14.8**	$ 12.3	$ 14.4
Contribution to consolidated net earnings – Canadian $	**$ 5.3**	$ 4.0	**$ 16.8**	$ 14.9	$ 18.5
Contribution to consolidated earnings per common share – Canadian $	**$ 0.04**	$ 0.04	**$ 0.15**	$ 0.14	$ 0.17
Net earnings weighted average foreign exchange rate – Canadian /US $	**$ 1.15**	$ 1.17	**$ 1.13**	$ 1.21	$ 1.30

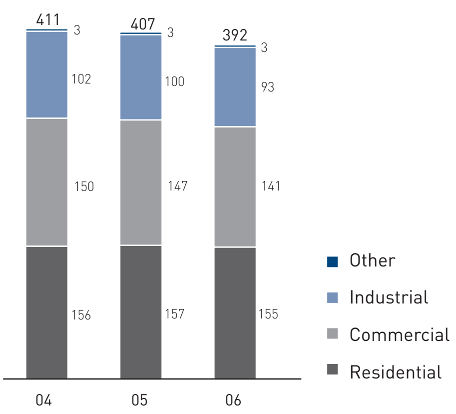
Bangor Hydro's contribution to consolidated net earnings was $4.6 million in Q4 2006 compared to $3.4 million in Q4 2005. For the year ended December 31, 2006, Bangor Hydro's contribution to consolidated net earnings was $14.8 million, compared to $12.3 million in 2005 and $14.4 million in 2004. Highlights 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 – 2004		**$ 14.4**
Increased energy sales volume		1.8
Increased depreciation expense, reflecting new depreciation study		(1.5)
2004 stranded cost purchased power expense less than amount used in setting rates		(1.1)
Increased NEPOOL related transmission expenses		(0.9)
Write-off in Q2 2004 of deferred costs disallowed in rates		1.1
All other		(1.5)
Contribution to consolidated net earnings – 2005	**$ 3.4**	**$ 12.3**
Increased overheads capitalized primarily as a result of capital expenditures on the Northeast Reliability Interconnect transmission project	2.6	5.2
Decreased energy sales largely due to warmer weather year over year	(0.4)	(1.8)
All other	(1.0)	(0.9)
Contribution to consolidated net earnings – 2006	**$ 4.6**	**$ 14.8**

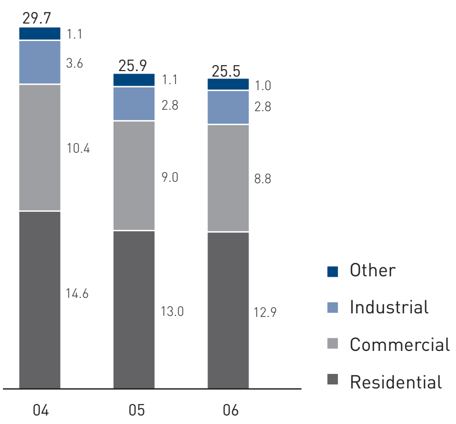
Bangor Hydro's contribution to consolidated net earnings was $5.3 million CAD in Q4 2006 compared to $4.0 million CAD in Q4 2005, due to the Canadian dollar equivalent of the variances discussed above and the $0.1 million impact of the stronger Canadian dollar. For the year ended December 31, 2006, net earnings contributed by Bangor Hydro was $16.8 million CAD compared to $14.9 million CAD for 2005 and $18.5 million CAD for 2004, due to the Canadian dollar equivalent of the variances discussed above and the $1.1 million impact of the stronger Canadian dollar in 2006 and $1.0 million impact of the stronger Canadian dollar in 2005.

ELECTRIC REVENUE

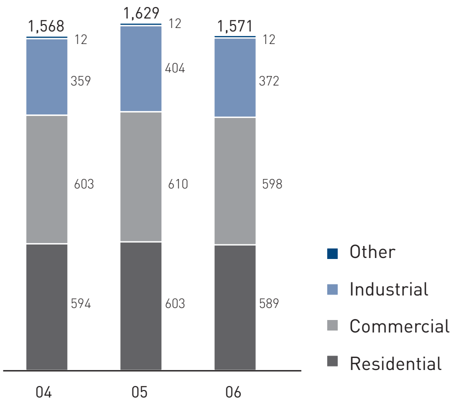
Q4 Electric Sales Volume
GWh



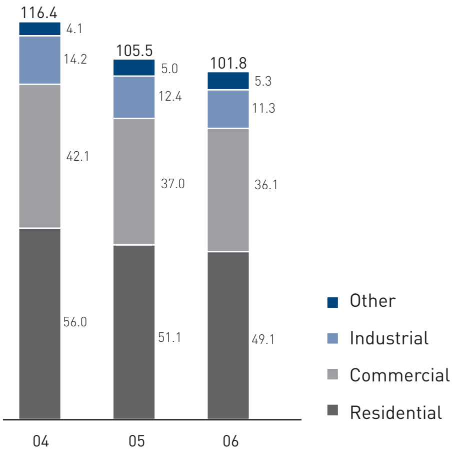
Q4 Electric Sales Revenues
millions of dollars



YTD Electric Sales Volume
GWh



YTD Electric Sales Revenues
millions of dollars



Q4 Average Revenue per MWh

	2006	2005	2004
Dollars per MWh	**$ 65**	$ 64	$ 72

YTD Average Revenue per MWh

	2006	2005	2004
Dollars per MWh	**$ 65**	$ 65	$ 74

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 decreased by $0.4 million in Q4 2006, to $25.5 million compared to $25.9 million in Q4 2005. For the year ended December 31, 2006, electric revenues were $101.8 million compared to $105.5 million for 2005 and $116.4 million in 2004. Highlights of the changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
T&D revenues – 2004		**$ 116.4**
Stranded cost rate reduction on March 1, 2005		(13.0)
Increased energy sales volume		1.8
All other		0.3
T&D revenues – 2005	**$ 25.9**	**$ 105.5**
Stranded cost rate reduction on March 1, 2005	–	(2.7)
Decreased energy sales volume due to warmer weather year over year	(0.4)	(1.8)
All other	–	0.8
T&D revenues – 2006	**$ 25.5**	**$ 101.8**

RESALE OF PURCHASED POWER, AND FUEL FOR GENERATION AND PURCHASED POWER

The company 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. Resale of purchased power increased in 2006 and 2005 due to increases in the rate at which BHE's power purchases were resold to a third party.

OPERATING, MAINTENANCE AND GENERAL EXPENSES

Operating, maintenance and general expenses decreased $0.7 million to $7.0 million in Q4 2006 compared to $7.7 million in 2005 and decreased $4.1 million to $27.1 million for the year ended December 31, 2006, compared to $31.2 million in 2005, primarily due to increased overheads capitalized primarily as a result of capital expenditures on the Northeast Reliability Interconnect ("NRI") transmission project.

Operating, maintenance and general expenses decreased $0.5 million to $31.2 in 2005 from $31.7 million in 2004, primarily due to reduced labour.

DEPRECIATION

Depreciation expense was unchanged at $3.2 million in Q4 2006 compared to Q4 2005; increased $0.5 million in 2006 relative to 2005; and increased $1.5 million in 2005 relative to 2004, due principally to the effect of plant additions. The results of BHE's depreciation study, completed in 2004, also affected the results.

REGULATORY AMORTIZATION

Regulatory amortization was $0.9 million higher in Q4 2006 at $2.0 million, compared to $1.1 million in Q4 2005 and was $1.8 million higher year-to-date 2006 at $12.6 million, compared to $10.8 million for the same period in 2005, primarily due to the new stranded cost levelizer amortization, implemented with the stranded cost rate reduction effective March 1, 2005.

For the year ended December 31, 2005 amortization expense was $10.8 million, compared to $15.2 million in 2004, a reflection of the new stranded cost levelizer deferral.

OTHER

Other income was $2.1 million in Q4 2006 compared to $0.8 million in Q4 2005 and $5.9 million in 2006, compared to $3.9 million for 2005, primarily due to increased allowance for funds used during construction related to NRI capital expenditures.

INTEREST

Bangor Hydro manages exposure through a combination of fixed and floating rate borrowings.

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).

OUTLOOK

Bangor Hydro net earnings are expected to be higher in 2007, as the Northeast Reliability Interconnect is constructed and comes into operation in Q4 2007.

DEBT MANAGEMENT

The weighted-average coupon rate on Bangor Hydro's long-term debt outstanding at December 31, 2006 was 7.22% (2005 – 7.18%). Approximately 60% of the debt matures over the next 12 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 5.86% as of December 31, 2006 (2005 – 5.55%).

Bangor Hydro has established the following credit facilities:

Short-term millions of dollars	Maturity		Maximum amount
Operating credit facility	3 year revolving	$	70.0

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, BHE expects to have sufficient access to competitively priced funds in the unsecured debt market.

OUTLOOK

BHE will finance a portion of the Northeast Reliability Interconnect project with debt in 2007. The remainder of the project was funded internally through the sale of common shares in BHE to Emera Inc. in Q4 2006.

OTHER, INCLUDING CORPORATE COSTS

All activities of Emera other than its two regulated electric utilities are incorporated into Other, including:

- Emera Energy Services, which purchases and sells natural gas and electricity on behalf of third parties and provides related energy asset management services. Emera Energy Services operates with minimal day-to-day commodity risk exposure. Volatility in natural gas markets usually results in increased opportunities for Emera Energy Services.
- A 12.9% interest in the $2 billion, 1,300 kilometer Maritimes & Northeast Pipeline that transports Nova Scotia's offshore natural gas to markets in Maritime Canada and the northeastern United States.
- Bear Swamp, a 50/50 joint venture in a 600 megawatt pumped storage hydro-electric facility in northern Massachusetts, which was acquired on May 24, 2005. As a pumped storage hydro-electric facility, the plant typically purchases power during lower priced off-peak periods and generates power during higher priced on-peak periods.
- Certain corporate-wide functions such as executive management, strategic planning, treasury services, tax planning, business development and corporate governance; and financing for the corporation's business outside of its regulated electric utilities.

Acquisition of Bear Swamp

In Q2 2005 Emera and Brookfield Power Corporation, in a 50/50 joint venture, acquired Bear Swamp, a 600 MW pumped storage hydro-electric facility in northern Massachusetts. Emera's share of the purchase price was $61.2 million including acquisition costs. The facility sells energy, capacity and ancillary products to the New England Power Pool. Also included in the acquisition is the nearby 10 MW Fife Brook run-of-river hydro-electric facility.

The acquisition has been accounted for under the purchase method of accounting using proportionate consolidation, and accordingly, Emera's pro-rata share of the results of operations since the date of acquisition have been included in the consolidated statement of earnings and the summary statement of earnings below.

Investment in Brunswick Pipeline

Brunswick Pipeline is a proposed $350 million greenfield pipeline project under development that will deliver natural gas from the planned Canaport™ Liquefied Natural Gas import terminal near Saint John, New Brunswick to markets in Canada and the US northeast. The 145 kilometer Brunswick Pipeline will travel through southwest New Brunswick and connect with the Maritimes and Northeast Pipeline at the Canada/US border near Baileyville, Maine. Emera has been an investor in M&NP since its inception in 1999.

Canaport™ LNG is a partnership of Repsol YPF, S.A. and Irving Oil Limited. Emera has negotiated a 25-year send or pay toll agreement with Repsol to transport natural gas through the Brunswick Pipeline. Emera has also negotiated agreements with its M&NP partner, Spectra Energy Corp, an affiliate of which will assist Emera in the Brunswick Pipeline permitting process, and construct and operate the pipeline on Emera's behalf.

Emera expects to finance the investment with internally generated cash flow and debt. The investment is forecast to provide a return on project equity of 11%–14%.

The project requires National Energy Board approval. NEB hearings were completed in November 2006, with a decision expected in Q2 2007. Assuming approval is granted, the pipeline is expected to be in service by the end of 2008.

Until the NEB approves the Brunswick Pipeline, Emera is being reimbursed by Repsol for project development costs. Accordingly, this project had no significant effect on Emera's earnings or cash flows in 2006.

Emera's net cash requirements related to Brunswick Pipeline are expected to be $65 million for 2007.

Investment in St. Lucia Electricity Services

St. Lucia Electricity Services Limited is a vertically integrated electric utility serving more than 50,000 customers on the Caribbean island of St. Lucia. Emera acquired a 19% equity interest in Lucelec for US $22 million in January 2007.

Lucelec has an exclusive license to generate, transmit and distribute electricity on the island to 2045. The utility has 66 MW of generating capacity, primarily oil fired, and 800 kilometers of electricity transmission and distribution assets. Lucelec is a cost of service utility, with a minimum rate of return of 10% on a 50% equity base. Emera financed the acquisition with existing credit facilities. Lucelec is expected to add approximately $1 to $2 million to Emera's annual consolidated net earnings.

Emera's strategy recognizes that the Caribbean market has attractive growth prospects and opportunities for the company to deploy its operational expertise. This modest investment in Lucelec provides Emera with a low risk vehicle to assess whether there is broader business potential for the company in the region, and at the same time, provides immediately accretive and attractive returns.

Sale of Assets of Emera Fuels

Effective Q3 2005 Emera sold its heating oil distribution business for proceeds of $18.6 million, which were used to pay down debt. A loss on disposition of $1.6 million after-tax was recognized in Q3 2005. The transaction reduced Emera's total assets by approximately $25 million (net assets by approximately $20 million). The reduction in annual after-tax net earnings and cash provided by operating activities is immaterial.

REVIEW OF 2006

Other Net Earnings

	Three months ended December 31		Year ended December 31		
millions of dollars (except earnings per common share)	**2006**	2005	**2006**	2005	2004
Emera Energy Services earnings before interest and taxes ("EBIT")	**$ 4.6**	$ 3.9	**$ 15.1**	$ 18.3	$ 17.7
Bear Swamp EBIT	**(0.8)**	1.7	**1.4**	4.2	–
M&NP equity earnings	**1.2**	1.7	**4.9**	6.5	6.2
Corporate Costs & Other	**(3.6)**	(0.2)	**(9.6)**	(7.0)	(15.6)
Earnings before interest and income taxes	**1.4**	7.1	**11.8**	22.0	8.3
Interest	**3.6**	9.5	**10.0**	7.4	13.2
Earnings before income taxes	**(2.2)**	(2.4)	**1.8**	14.6	(4.9)
Income taxes	**(0.5)**	(2.1)	**(2.9)**	(1.4)	(6.7)
Net earnings from continuing operations	**(1.7)**	(0.3)	**4.7**	16.0	1.8
(Loss) earnings from discontinued operations, net of tax	**–**	–	**–**	(0.9)	2.2
Contribution to consolidated net earnings	**$ (1.7)**	$ (0.3)	**$ 4.7**	$ 15.1	$ 4.0
Contribution to consolidation earnings per share	**$ (0.01)**	$ –	**$ 0.05**	$ 0.14	$ 0.04

The contribution of Other to consolidated net earnings was $(1.7) million in Q4 2006, compared to $(0.3) million in Q4 2005. Annual contribution to consolidated net earnings was $4.7 million in 2006 compared to $15.1 million in 2005 and $4.0 million in 2004. 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 – 2004		**$ 4.0**
Increased EBIT in Emera Energy Services as a result of increased marketing opportunities		0.6
Addition of Bear Swamp hydro-electric facilities EBIT		4.2
Foreign exchange gains reflecting an adjustment to refine prior years' foreign exchange		5.2
Capitalization of previously expensed business development costs to the Bear Swamp cost of net assets purchased		2.5
Loss on disposition of Emera Fuels, net of tax		(1.6)
Write-off of Greyhawk Gas Storage venture in Q1 2004		1.9
All other		(1.7)
Contribution to consolidated net earnings – 2005	**$ (0.3)**	**$ 15.1**
Increased (decreased) EBIT in Emera Energy Services as a result of increased (decreased) natural gas marketing opportunities	0.7	(3.2)
Reduced Bear Swamp EBIT due to decreased electric margin and mark-to-market losses related to 2007 hedged positions	(2.5)	(2.8)
Loss in Emera Fuels in 2005, net of tax	–	0.9
Capitalization in Q4 2005 of previously expensed business development costs to the Bear Swamp cost of net assets purchased	(2.5)	(2.5)
Reversal of foreign exchange gain in Q4 2005 that had been recognized earlier in 2005 related to settlement of US denominated debt	5.9	–
Foreign exchange gains recognized in 2005 reflecting an adjustment to refine prior years' foreign exchange	–	(5.2)
All other	(3.0)	2.4
Contribution to consolidated net earnings – 2006	**$ (1.7)**	**$ 4.7**

EMERA ENERGY SERVICES

Emera Energy Services EBIT increased quarter over quarter to $4.6 million in Q4 2006 from $3.9 million in Q4 2005 as a result of increased volatility in natural gas markets. For the year ended December 31, 2006 EBIT decreased to $15.1 million from $18.3 million in 2005 as a result of moderating margins in natural gas markets. For the year ended December 31, 2005 EBIT was $18.3 million compared to $17.7 million in 2004 due to increased weather-related volatility in the market, including gains on longer term contracts in 2005.

BEAR SWAMP

Bear Swamp EBIT represents Emera's investment in the Bear Swamp joint venture, which was acquired in Q2 2005.

Bear Swamp incurred a loss before interest and taxes of $0.8 million in Q4 2006 compared to earnings of $1.7 million in Q4 2005; and $1.4 million in 2006 compared to earnings of $4.2 million for the same period in 2005. In 2005 Bear Swamp's margins were strong, because peak prices rose as a result of the impact of an active hurricane season. During 2006, margins were weaker due to milder weather patterns. A hedging program was implemented in 2006 to provide more consistent margins and resulted in a mark-to-market loss, which will reverse in 2007.

M&NP EQUITY EARNINGS

Equity earnings for M&NP were $1.2 million in Q4 2006 compared to $1.7 million in Q4 2005, and were $4.9 million year-to-date 2006 compared to $6.5 million for the same period in 2005, primarily due to expansion costs expensed pending regulatory approval.

For the year ended December 31, 2005 M&NP equity earnings were $6.5 million compared to $6.2 million in 2004. Increases in tolls collected for the US operations have been offset by the write-off of previously expensed cost for pipeline expansion on the US pipeline.

On May 16, 2006 M&NP filed an application with the FERC to expand its US pipeline system to carry volumes from the proposed Brunswick Pipeline to markets in the US northeast. Construction of the proposed expansion facilities is anticipated to begin in June 2007, in conjunction with the building of Brunswick Pipeline. M&NP is expensing development costs associated with the expansion. Once FERC approval is obtained, likely in 2007, these will be capitalized as part of the US pipeline expansion.

In 2004 M&NP filed a Notice of Rate Increase for its US operations. Effective January 1, 2005 M&NP was permitted to collect proposed rates from customers, pending approval of new rates. On June 28, 2005 M&NP submitted an offer of settlement to the FERC, which was approved without modification on May 15, 2006. The company had been recognizing its best estimate of rates in equity earnings and energy marketing margin in Emera Energy Services based on the terms of the proposed settlement. As a result, there were no adjustments to earnings to account for the approved new rates.

CORPORATE COSTS & OTHER

Expenses related to Corporate Costs & Other increased quarter over quarter to $3.6 million in Q4 2006 from $0.2 million in Q4 2005; and increased year over year to $9.6 million in 2006 from $7.0 million in 2005 largely as a result of the capitalization in Q4 2005 of previously expensed business development costs to the Bear Swamp cost of net assets purchased, partially offset by dividend income received in 2006.

For the year ended December 31, 2005 expenses related to Corporate Costs & Other decreased to $7.0 million from $15.6 million in 2004 largely due to the write-off in 2004 of the Greyhawk Gas Storage Venture, partially offset by the capitalized business development costs in 2005 referred to above.

INTEREST

Interest expense decreased quarter over quarter to $3.6 million in Q4 2006 from $9.5 million in Q4 2005 as a result of a foreign exchange gain reversing in Q4 2005 that had been recognized earlier in the year.

For the year ended December 31, 2006, interest increased to $10.0 million from $7.4 million in 2005 largely as a result of foreign exchange gains recognized in 2005 reflecting an adjustment to prior years' foreign exchange.

For the year ended December 31, 2005 interest decreased to $7.4 million from $13.2 million in 2004 largely due to the foreign exchange gains recognized in 2005 as referred to 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, excluding M&NP equity earnings that are recorded net of tax. Variations in income tax expense are largely affected by withholding taxes paid on cross-border dividends and interest, completion of prior years' tax returns, and corporate tax sharing agreements.

OUTLOOK

Other net earnings are expected to increase marginally in 2007.

M&NP equity earnings are expected to increase due to the proposed tolling agreement related to the Canadian portion of the investment, and capitalization of expansion costs in the US in 2007 that were expensed in 2006 and prior years.

Bear Swamp EBIT is expected to increase in 2007 as a result of the reversal of a mark-to-market loss recognized in 2006 related to 2007 hedge positions and new capacity revenues.

Other net earnings will also include allowance for funds under construction related to the Brunswick Pipeline in 2007.

Emera Energy Services EBIT is expected to decrease in 2007. SOEP gas compression will increase the volume of gas out of SOEP, and reduce the opportunity to manage fluctuations in gas supply, which in turn will reduce margins on gas sales.

Corporate and Other expenditures are expected to increase in 2007, reflecting increased business development activities and dividend income received in 2006.

DEBT MANAGEMENT

In June 2006, Emera amended its operating and acquisition credit facilities by combining its $200 million operating facility and $400 million acquisition facility into one $600 million facility for operating and acquisition financing requirements.

Emera has established the following credit facilities outside its regulated electric utilities:

Short-term millions of dollars	Maturity	Maximum amount
Operating and acquisition credit facility	1 year revolving	$ 600.0

In Q2 2006, Standard & Poor's rating agency lowered the corporate and senior unsecured debt credit ratings of Emera, citing concerns related to the recovery of fuel-related expenses under the current regulatory framework in Nova Scotia; an evolving fuel procurement strategy; and upcoming challenges related to the approval, financing and execution of several proposed capital projects as reasons for the change. The negative outlook was again confirmed in Moody's December 2006 credit opinion report.

The change could have cost implications for Emera and Nova Scotia Power as the companies re-finance existing debt in future years, issue new capital or enter into new fuel procurement arrangements.

The ratings issued by Dominion Bond Rating Service and Moody's Investor Services are unchanged.

Emera has the following available credit ratings:

	DBRS		S&P		Moody's	
	2006	2005	**2006**	2005	**2006**	2005
Long-term corporate	**BBB (high)**	BBB (high)	**BBB**	BBB +	**Baa2**	N/A
Senior unsecured debt	**BBB (high)**	BBB (high)	**BBB**	BBB	**Baa2**	Baa2

On a consolidated basis, Emera's target percentage of debt to total capitalization is 50%–55%, of which 10%–25% would be exposed to short-term rates. The company manages long-term debt terms such that the average is not less than ten years.

CONSOLIDATED BALANCE SHEETS

Significant changes in the consolidated balance sheets between December 31, 2006 and December 31, 2005 include:

millions of dollars	Increase (Decrease)	Explanation
Cash and cash equivalents	**$ (13.9)**	Refer to the consolidated cash flows highlights section below.
Accounts receivable	**21.8**	2005 and 2006 electricity price increases, lower accounts receivable securitization, and the reclassification of the natural gas price adjustment from long-term receivables in NSPI, partially offset by payment of the receivable from Pengrowth, and decreased pricing in Emera Energy Services.
Inventory	**37.5**	Higher fuel inventory levels and pricing in NSPI.
Prepaid expenses	**38.0**	Increased posted margin paid to counterparties in Emera Energy Services.
Energy marketing assets (including long-term portion)	**19.2**	Increased long-term deal activity in Emera Energy Services and the addition of Bear Swamp in Q2 2005. Energy marketing assets, net of energy marketing liabilities, has decreased due to the realization of long-term contracts.
Long-term receivables	**(48.4)**	Reclassification of the natural gas price adjustment in NSPI to accounts receivable.
Deferred charges	**(44.8)**	Ongoing amortization and a reduction in NSPI's deferred pension asset.
Property, plant and equipment and construction work-in-progress	**52.7**	Capital additions, including the NRI project and Brunswick Pipeline, in excess of depreciation expense.
Short-term debt	**45.1**	Increased borrowings to finance NRI project and increased posted margin requirements from Emera Energy Services' counterparties.
Accounts payable and accrued charges	**37.4**	Timing of payments and increased accruals in NSPI, increased NRI-related accruals, and a payable related to the Brunswick Pipeline project, partially offset by decreased pricing in Emera Energy Services.
Income tax payable	**37.8**	NSPI's tax expense in excess of installments.
Energy marketing liabilities (including long-term portion)	**23.1**	Increased long-term deal activity in Emera Energy Services and the addition of Bear Swamp in Q2 2005.
Deferred credits	**(11.4)**	Reduction in BHE's Maine Yankee decommissioning liability and deferred pension liability.
Long-term debt (including current portion)	**(123.9)**	Reduction in NSPI's Commercial Paper due to increased cash flow from operations.
Shareholders' equity	**41.9**	Net earnings in excess of common dividends paid, and common shares issued as a result of stock options being exercised and stock purchase plans.

OUTSTANDING SHARE DATA

Issued and outstanding:	Millions of Shares	Common Share Capital millions of dollars
January 1, 2005	108.87	$ 1,017.3
Issued for cash under purchase plans	0.43	7.9
Options exercised under senior management share option plan	0.80	13.0
Share-based compensation	–	1.0
December 31, 2005	110.10	$ 1,039.2
Issued for cash under purchase plans	0.45	8.6
Options exercised under senior management share option plan	0.38	6.7
Share-based compensation	–	0.7
December 31, 2006	**110.93**	**$ 1,055.2**

As at January 31, 2007 the number of issued and outstanding common shares was 110.98 million.

LIQUIDITY AND CAPITAL RESOURCES

The company generates funds primarily through its operations in regulated utilities involving the generation, transmission and distribution of electricity. Circumstances that could affect the company's ability to generate funds include fuel commodity price changes, general economic downturns in Nova Scotia and Maine, and regulatory decisions affecting customer rates. In addition to internally generated funds, the company has access to debt capital markets, including $782 million in syndicated bank lines of credit, a $400 million commercial paper program, which is 100% backed up by a syndicated bank line of credit, and an $80 million accounts receivable securitization program. The company's financing facilities are expected to provide sufficient access to money markets and capital markets necessary to maintain acceptable levels of liquidity relative to current cash forecasts.

Emera and Nova Scotia Power have debt shelf prospectuses in the amounts of $300 million and $400 million respectively that provide the companies with access to long-term debt. Emera and Nova Scotia Power have $300 million and $150 million respectively that remained unused at December 31, 2006. The prospectuses expire in April 2007 and will be renewed. The company also has access to equity capital markets for both common and preferred shares.

CONSOLIDATED CASH FLOW HIGHLIGHTS

Significant changes in the consolidated cash flow statements between December 31, 2006 and December 31, 2005 include:

Three months ended December 31 millions of dollars	2006	2005	Explanation
Cash and cash equivalents, beginning of period	**$ 4.5**	$ 19.2	
Provided by (used in):			
Operating activities	**106.7**	(36.3)	In 2006, cash earnings and improved non-cash working capital. In 2005, reduced non-cash working capital, partially offset by cash earnings.
Investing activities	**(83.0)**	58.5	In 2006, capital spending, including NRI project. In 2005, return of the escrow deposit made on a proposed acquisition, decreased restricted cash, and proceeds received on the sale of Emera Fuels, partially offset by capital spending.
Financing activities	**(20.6)**	(19.9)	In 2006, reduced debt levels and dividends on common shares. In 2005, reduced debt levels and dividends on common shares, partially offset by increased accounts receivable securitized and receipt from long-term Pengrowth receivable.
Cash and cash equivalents, end of year	**$ 7.6**	$ 21.5	

Year ended December 31 millions of dollars	2006	2005	Explanation
Cash and cash equivalents, beginning of period	**$ 21.5**	$ 42.7	
Provided by (used in):			
Operating activities	**345.8**	164.3	In 2006, cash earnings, partially offset by reduced non-cash working capital. In 2005, cash earnings, partially offset by reduced non-cash working capital.
Investing activities	**(203.0)**	(117.2)	In 2006, capital spending, including NRI project. In 2005, capital spending and the acquisition of Bear Swamp, partially offset by the return of escrow deposit made on a proposed acquisition and proceeds received on the sale of Emera Fuels.
Financing activities	**(156.7)**	(68.3)	In 2006, dividends on common shares, reduction in debt levels, and decrease in the amount of accounts receivable securitized, partially offset by common shares issued. In 2005, dividends on common shares, partially offset by common shares issued and receipt from long-term Pengrowth receivable.
Cash and cash equivalents, end of year	**$ 7.6**	$ 21.5	

CONTRACTUAL OBLIGATIONS

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

millions of dollars					Payments Due by Period
	Total	2007	2008–2009	2010–2011	After 2011
Long-term debt	**$ 1,660.8**	$ 171.4	$ 251.7	$ 110.6	$ 1,127.1
Operating leases	**29.6**	7.4	12.9	6.4	2.9
Purchase obligations	**1,821.8**	441.8	619.6	304.9	455.5
Other long-term obligations	**316.9**	0.8	0.9	2.0	313.2
Total contractual obligations	**$ 3,829.1**	$ 621.4	$ 885.1	$ 423.9	$ 1,898.7

Operating lease obligations: Emera's operating lease obligations consist of operating lease agreements for office space, telecommunications services, vehicles and photocopiers.

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

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 for 2006 were approximately $200 million. Significant capital projects included:

- $62 million CAD related to Northeast Reliability Interconnect project in BHE;
- Installation of a Low NOx Combustion Firing system on NSPI's Lingan Unit 3;
- Installation of turbine blades at NSPI's Tufts Cove 1; and
- A transmission line upgrade in BHE.

In December 2006, NSPI filed work orders for approval by the UARB for the following capital projects:

- Installation of a Low NOx Combustion Firing system on Lingan Units 2 and 4 at approximately $4 million each.
- Installation of a pulse air fabric filter baghouse on Trenton Unit 5 for approximately $30 million.
- Rebuild of generator on Trenton Unit 5 for approximately $17 million.

In November 2005, NSPI filed a Notice of Application for the construction of capital projects associated with achieving the air emissions requirements contained in the Provincial environmental regulations. These capital projects are for the installation of air emissions abatement equipment at the Lingan generating station. Total investment associated with this equipment was projected at $177 million.

NSPI's regulator, the UARB, approved $5 million for the installation of a Low NOx Combustion Firing system on Lingan Unit 3 on April 5, 2006, which has now been installed. Nova Scotia Power requested to discontinue its application for the remaining $172 million for the flue gas desulphurization equipment in response to requests from stakeholders for more study. The UARB agreed with NSPI's request. A hearing on this matter took place on June 19, 2006. Participants in the hearing agreed to take part in an Integrated Resource Plan ("IRP"), which will analyze a variety of factors to assess how best to proceed. The IRP is expected to be completed in Q3 of 2007.

OUTLOOK

Emera's capital budget for 2007 includes approximately $120 million for NSPI, which is generally directed to customer growth and system reliability, planned and preventative maintenance, productivity-related investments, and air emissions upgrades. BHE expects to invest approximately $90 million CAD, including approximately $70 million CAD for several transmission projects. Brunswick Pipeline expects to invest approximately $65 million.

The company expects to finance its capital expenditures with funds from operations and debt. Bangor Hydro will finance a portion of the Northeast Reliability Interconnect project with a long-term debt issue in 2007.

OFF-BALANCE SHEET ARRANGEMENTS

Upon privatization in 1992, NSPI became responsible for managing a portfolio of approximately $1.05 billion of defeasance securities held in trust. The defeasance securities must provide the principal and interest streams to match the related defeased debt. Approximately 71% 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 consists of investments with market values higher than the related debt, reducing the future risk of this portion of the portfolio.

NSPI has an agreement with an independent trust administered by a Canadian chartered bank whereby it can sell accounts receivable to the trust on a revolving non-recourse basis. As of December 31, 2006, the company had sold $80.0 million (2005 – $80.0 million) of net accounts receivable. The net proceeds from the sale were used to repay a portion of the company's debt. The agreement is in place until May 2009, with the intention that it will be renewed at that time. Securitization provides NSPI with an alternative source of short-term funding. For the year ended December 31, 2006, the average all-in cost of this funding was 4.30% (2005 – 2.97%). In the event of termination of this arrangement, NSPI would utilize another liquidity facility to meet the ongoing operations of the business.

FINANCIAL AND COMMODITY 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 derivative instruments consisting mainly of foreign exchange forward contracts, interest rate options and swaps, and oil and gas options and swaps.

Instruments that meet stringent documentation requirements, and can be proven to be effective both at the inception and over the term of the instrument, qualify for hedge accounting. Specifically, amounts paid or received are deferred and recognized in earnings in the same period the related hedged item is realized. Where the documentation or effectiveness requirements are not met, the non-qualifying instruments are marked-to-market and recognized in earnings in the reporting period.

The company has deferred payments and receipts on derivative instruments that are designated and effective as hedges and are recognized in the following categories on the balance sheet:

Deferred Hedging Losses Recognized on the Balance Sheet

millions of dollars	**December 31 2006**	December 31 2005
Inventory	**$ 5.2**	$ 0.2
Deferred charges	**0.9**	1.1
Deferred hedging losses	**$ 6.1**	$ 1.3

For the three-month period and year ended December 31, the impacts of effective hedges recognized in earnings were recorded in the following categories:

Hedging Impact Recognized in Earnings

millions of dollars	Three months ended December 31		Year ended December 31	
	2006	2005	**2006**	2005
Fuel and purchased power decrease (increase)	**$ 15.7**	$ (3.9)	**$ 48.4**	$ (20.5)
Interest expense increase	**(0.1)**	(0.4)	**(0.3)**	(1.9)
Hedging earnings impact	**$ 15.6**	$ (4.3)	**$ 48.1**	$ (22.4)

The company also enters into non-hedging derivative financial and commodity instruments. These instruments, along with the non-qualifying hedges referred to above, are marked-to-market at each reporting date.

The company had recorded the following mark-to-market transactions included on the balance sheet and recognized in earnings:

Mark-to-Market Gains (Losses) Recognized on the Balance Sheet

millions of dollars	**December 31 2006**	December 31 2005
Accounts receivable	**–**	$ 4.5
Energy marketing assets	**$ 39.3**	20.1
Deferred charges	**–**	0.4
Energy marketing liabilities	**(38.1)**	(15.0)
Mark-to-market gains	**$ 1.2**	$ 10.0

Mark-to-Market Gains (Losses) Recognized in Earnings

millions of dollars	Three months ended December 31		Year ended December 31	
	2006	2005	**2006**	2005
Other revenue	**$ 1.1**	$ (0.5)	**$ (2.1)**	$ 4.6
Fuel and purchased power	**(2.1)**	8.5	**(6.4)**	8.5
Interest	**(0.2)**	0.4	**(0.3)**	–
Mark-to-market (losses) gains	**$ (1.2)**	$ 8.4	**$ (8.8)**	$ 13.1

In determining the fair value of derivative financial instruments, the company has relied on quoted market prices as at the reporting date.

TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera purchased natural gas transportation capacity totalling $6.2 million (2005 – $5.1 million) during the three months ended December 31, 2006, and $29.3 million (2005 – $21.7 million) during the year ended December 31, 2006, 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, 2006 the amount payable to the related party is $3.4 million (December 31, 2005 – $4.5 million), is non-interest bearing and is under normal credit terms.

DISCLOSURE AND INTERNAL CONTROLS

Emera's management is responsible for the design of disclosure controls and procedures, as defined under Multilateral Instrument 52-109, for the year ended December 31, 2006 in order to provide reasonable assurance that material information is made known to them. Management is also responsible for the design of internal controls over financial reporting in order to provide reasonable assurance regarding the reliability of financial statements prepared for external purposes in accordance with GAAP.

The President and Chief Executive Officer and the Chief Financial Officer, with the assistance of company employees, have evaluated the effectiveness of the design and operation of disclosure controls and procedures. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer have concluded that the company's disclosure controls and procedures are adequate and effective in ensuring material information relating to Emera and its consolidated subsidiaries is made known to them and is complete and reliable.

The President and Chief Executive Officer and the Chief Financial Officer, with the assistance of company employees, have evaluated the effectiveness of the design of internal controls and procedures. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer have concluded that the design of these internal controls was effective.

There have been no changes in Emera's internal controls over financial reporting during the quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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, natural gas price adjustment receivable, asset retirement obligations, useful lives for depreciable assets, and goodwill impairment assessments. Actual results may differ from these estimates.

Rate Regulation

NSPI's and BHE's accounting policies are subject to examination and approval by their respective regulators. As a result, their rate-regulated accounting policies may differ from accounting policies for non-rate-regulated companies. These differences occur when the regulators render their decisions on rate applications or other matters and generally involve the timing of revenue and expense recognition.

The accounting for these items is based on the expectation of the future actions of the regulators. For example, NSPI does not record future income taxes. The taxes payable method is prescribed by the regulator for rate-making purposes and there is reasonable expectation that the regulator will provide for all such future income taxes to be recovered in rates when they become payable. Similarly, the deferral of differences between the amounts included in rates and regulations and the realization of specified expenses is based on the expectation that the regulators will approve the refund to or recovery from ratepayers of the deferred balance.

If the regulators' future actions are different from the companies' expectations, 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 a defined benefit pension plan. 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 significantly 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.

The following table reflects the sensitivities associated with a change in certain actuarial assumptions. The impact of increasing the expected rate of return on plan assets or the discount rate by 0.5% on the accrued benefit obligation recorded in the 2006 year end consolidated financial statements and the 2007 benefit cost and 2007 year end accrued benefit asset or liability would be as follows:

millions of dollars	NSPI	BHE
Impact of increasing the rate of return assumption by 0.5%:		
Accrued benefit obligations, December 31, 2006	–	–
Benefit cost for the year ended December 31, 2007	$ (3.0)	$ (0.3)
Accrued benefit asset, December 31, 2007	$ 3.0	–
Accrued benefit liability, December 31, 2007	–	$ (0.3)
Impact of increasing the discount rate assumption by 0.5%:		
Accrued benefit obligations, December 31, 2006	$ (61.4)	$ (8.3)
Benefit cost for the year ended December 31, 2007	$ (6.7)	$ (0.6)
Accrued benefit asset, December 31, 2007	$ 6.7	–
Accrued benefit liability, December 31, 2007	–	$ (0.6)

The discount rate used to determine benefit costs is based on 'A' grade long-term Canadian corporate bonds for NSPI's pension plan and US corporate bonds for BHE's pension plan. The discount rate is determined with reference to bonds which have the same duration as the accrued benefit obligation as at January 1 of the fiscal year rounded to the nearest 25 basis points. NSPI's rate was 5.25% for 2006, reduced from 6.0% for 2005 and BHE's rate was 5.75% for 2006, reduced from 6.0% in 2005. The expected rate to be used for 2007 is 5.25% for NSPI and 6.00% for BHE.

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts. The 2006 and 2005 benefit cost calculations assumed that plan assets would earn a rate of return of 7.5% for NSPI and 8.0% for BHE. The 2007 benefit cost calculation is expected to use the same asset return assumptions.

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 BHE. 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. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. As of December 31, 2006, unbilled revenues amount to $82.3 million (2005 – $71.8 million) on a base of annual electric revenues of approximately $1.1 billion (2005 – $1.1 billion).

Natural Gas Price Adjustment Receivable

NSPI's existing long-term 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 to be settled in November 2007. Management has made a best estimate of the price rebate based on the contract specifications using actual and forward marketing 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.

At December 31, 2006, the asset retirement obligations recorded on the balance sheet were $78.1 million (2005 – $74.1 million). The company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $315.9 million, which will be incurred between 2007 and 2061. The majority of these costs will be incurred between 2020 and 2039.

Property, Plant and Equipment

Property, plant and equipment represents 71% 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 a significant 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 intervenors, 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 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 2004 Bangor Hydro completed a depreciation study. The study concluded that the company's accumulated depreciation was understated by approximately $6.6 million. The company received approval from FERC to implement the results of the depreciation study effective January 1, 2004. As a result of the study, Bangor Hydro began amortizing the $6.6 million over the average remaining service lives of the major plant asset classifications. Bangor Hydro also adjusted the composite depreciation rates for 2004 to reflect shorter lives as recommended by the study.

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 that 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 2006 or 2005.

CHANGES IN ACCOUNTING POLICIES

In 2006, the company adopted the new accounting guideline related to conditional asset retirement obligations. In addition, Nova Scotia Power changed its methodology for inventory valuation.

Conditional Asset Retirement Obligations

In December 2005, the Canadian Institute of Chartered Accountants ("CICA") issued Emerging Issues Committee Abstract 159 Conditional Asset Retirement Obligations ("EIC-159"). EIC-159 is to be applied retroactively, with restatement of prior periods, to financial statements for interim and annual reporting periods ending after March 31, 2006. EIC-159 was issued in response to the diverse accounting practices that have developed with respect to the timing of liability recognition when the timing and/or method of settlement are conditional on a future event.

As a result of adopting EIC-159, the company has determined that it has conditional asset retirement obligations related to the disposal of polychlorinated biphenyls ("PCBs"). As at December 31, 2006, property, plant and equipment has increased by $0.5 million (2005 – $0.6 million), accumulated depreciation has decreased by $2.0 million (2005 – $1.8 million), and asset retirement obligations have increased by $2.5 million (2005 – $2.4 million). There is no impact to net earnings in 2006 and 2005.

Inventory

In August 2006, Nova Scotia Power changed its method of costing fuel inventory from the first-in, first-out method to the weighted average cost method to provide more appropriate information. The change in accounting policy was approved by the UARB.

The CICA Handbook Section 1506 Accounting Changes requires that changes in accounting policies be applied retroactively to all prior periods presented for comparative purposes. Nova Scotia Power applied the change in accounting policy retroactively but did not restate prior periods as the necessary adjustments were considered immaterial. The change in accounting policy resulted in a cumulative adjustment to the opening balance of fuel inventory in Q3 2006 of $1.0 million. As a result, NSPI decreased inventory by $1.0 million and increased fuel expense by $1.0 million in Q3 2006.

Future Accounting Policy Changes

The CICA has issued standards 1530 Comprehensive Income, 3855 Financial Instruments – Recognition and Measurement, and 3865 Hedges, which are applicable to interim and annual financial statements beginning on or after October 1, 2006. The company is presently finalizing the effect of the new standards. The following provides more information on each standard.

Comprehensive Income: As a result of the issued standard, a new item, accumulated other comprehensive income ("AOCI"), will be recognized in the shareholders' equity section of the consolidated balance sheets beginning in 2007. AOCI will include the unrealized foreign exchange translation adjustments on the company's self-sustaining foreign operations, the effective portion of changes in fair value of derivatives meeting the requirements for cash flow hedges, and unrealized gains and losses on financial assets classified as available-for-sale.

Financial Instruments – Recognition and Measurement: As a result of the new standard, financial assets must be classified as loans and receivables, held-for-trading, available-for-sale, or held-to-maturity. Financial liabilities must be classified as either held-for-trading, or other than held-for-trading. Loans and receivables, held-to-maturity financial assets, and other than held-for-trading financial liabilities are recognized at amortized cost. Held-for-trading financial assets and liabilities will be recognized at fair value with any changes in fair value recognized in net income. Available-for-sale financial assets will be recognized at fair value with any changes in fair value recognized in other comprehensive income. There are provisions to recognize certain available-for-sale financial assets at cost.

Hedges: The new standard outlines the criteria for applying hedge accounting to cash flow hedges, fair value hedges, and hedging foreign currency fluctuations on self-sustaining foreign operations. Cash flow hedges are recognized on the balance sheet at fair value with the effective portion of the hedging relationship recognized in other comprehensive income. Any ineffective portion of the cash flow hedge must be recognized in net earnings. Amounts recognized in AOCI are reclassified to net income in the same periods in which the hedged item is recognized in net earnings. Fair value hedges and the related hedged items are recognized on the balance sheet at fair value with any changes in fair value recognized in net income. To the extent the fair value hedge is effective, the changes in fair value of the hedge and the hedged item will offset each other. Hedges of self-sustaining foreign operations are recognized at fair value with any changes in fair value recognized in other comprehensive income.

DIVIDENDS AND PAYOUT RATIOS

Emera Inc.'s common dividend rate was $0.89 ($0.2225 per quarter) per common share in 2006 and 2005, representing a payout ratio of approximately 78% for 2006 (2005 – 80%). In January 2007, the Board of Directors approved the common share dividend of $0.89 per share ($0.2225 per quarter).

BUSINESS RISKS AND ENTERPRISE RISK MANAGEMENT

RISK MANAGEMENT

Significant risk management activities for Emera are overseen by the Enterprise Risk Management Committee to ensure that risks are appropriately assessed, monitored and controlled within predetermined risk tolerances established through Board of Directors 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, credit risk, interest rates, and regulatory risk.

Commodity Prices

Substantially all of the company's annual fuel requirement is subject to fluctuation in commodity market prices, prior to any commodity risk management activities. NSPI 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 with credit-worthy counterparties. 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 the company's coal and petroleum coke supply comes from international suppliers at prevailing market prices. The company has entered into fixed-price contractual arrangements with several suppliers as part of the fuel procurement portfolio strategy. Physical contracts are used to hedge coal price risk due to the lack of liquidity in the financial markets for coal. The approximate percentage of coal and petcoke requirements contracted at December 31, 2006 is as follows:

- 2007 – 95%
- 2008 – 50%
- 2009 – 30%
- 2010 – 10%

Heavy Fuel Oil

NSPI manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options and futures contracts. The approximate percentage of heavy fuel oil requirements hedged and contracted as at December 31, 2006 is as follows:

- 2007 – 100%
- 2008 – 35%
- 2009 – 5%

Natural Gas

NSPI has entered into multi-year contracts to purchase approximately 61,600 mmbtu of natural gas per day. 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 where available for resale. Fixed price gas volumes not required for generation will be resold into the gas market with the margin managed using financial instruments. As at December 31, 2006, amounts of natural gas volumes that have been economically and/or financially hedged and contracted are approximately as follows:

Natural gas burn:

- 2007 – 95%
- 2008 – 35%
- 2009 – 30%
- 2010 – 30%

Natural gas resale:
- 2007 – 95%
- 2008 – 70%
- 2009 – 65%
- 2010 – 65%

Fuel Mix
The ability to switch fuel provides a dynamic and effective option in managing commodity price and supply risk.

Foreign Exchange
The risk due to fluctuation of the Canadian dollar against the US dollar for the cost of fuel is measured and managed. In 2007, NSPI expects approximately 80% of its anticipated net fuel costs to be denominated in US dollars; USD from sales of surplus natural gas will provide a natural hedge against a portion of USD fuel costs. Forward contracts are used to manage the exposure to fluctuating USD exchange rates. Forward contracts are in place for over 95% of 2007 anticipated USD net fuel costs. Forward contracts to buy US $815.4 million over 2007 to 2010 at a weighted average rate of CAD $1.1374 were outstanding at December 31, 2006. Forward contracts to sell US $66.2 million in 2007 at a weighted average rate of CAD $1.1404 were outstanding at December 31, 2006.

Interest Rates
Emera manages interest rate risk through a combination of fixed and floating borrowing and a hedging program. Prior to hedging, floating-rate debt is estimated to represent approximately 14% of total debt in 2007. Interest rate caps are used to limit exposure to movements of interest rates on floating debt. For 2007, interest on approximately 86% of floating debt is capped at a weighted-average rate of 4.75%.

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.

Regulatory Risk

Nova Scotia Power
NSPI faces risk with respect to the timeliness and certainty of full recovery of costs, particularly fuel costs in light of their magnitude and volatility. A central provision of the approved settlement agreement following the 2007 rate application is an agreement in principle that the UARB should establish a fuel adjustment mechanism for Nova Scotia Power to ensure actual fuel costs are recovered from customers. Hearings on this subject are expected in mid-2007.

During 2006 the Province of Nova Scotia proposed, and later passed, regulations under the Electricity Act that set out future requirements for energy from renewable sources. The regulations require NSPI to meet targets for an additional 5% of energy from renewable sources in 2010, and a further 5% in 2013. In December NSPI announced solicitation for 130 MW of renewable energy capacity, which represents a significant portion of the energy required during the first target period.

The government has also passed Wholesale Market Rules regulation, which allows NSPI's six municipal utilities to purchase electricity, including renewable energy, directly from suppliers. The Province continues to assess measures that would enable the sale of renewable energy directly from power purchasers to retail customers. The changes reflect policy directions set out in the Nova Scotia Energy Strategy of 2001. NSPI continues to work closely with government to ensure that changes in the electricity do not negatively affect customers or the utility.

Bangor Hydro

Bangor Hydro's business consists of four primary components, which are each governed by their own regulatory structure. The components include distribution, transmission, stranded costs and supply (metering, billing and settlement).

BHE's distribution business operates under an Alternate Rate Plan, which is in place until December 2007. The ARP requires BHE to decrease rates each year by an assumed productivity increase of approximately 2.5% per year. As part of the ARP, a penalty is triggered if BHE does not meet certain specified service quality indices. Under the current ARP, BHE does not have any recourse to the MPUC should costs rise faster than revenues. However, the ARP does provide BHE with the potential opportunity to earn a higher return on equity than under a more traditional cost-of-service regulatory structure. In Q4 2006 BHE announced its intention to file a request for changes in both its distribution rates and stranded cost rates, to go into effect in Q1 2008. Bangor Hydro's filing requests an increase in distribution rates as a result of shrinkage in overall load. The increase is substantially offset by a requested reduction in stranded cost rates.

The transmission business of BHE is primarily regulated by the FERC. The rates charged are determined by formula and driven by the annual report to the FERC. 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. BHE's return on equity on its transmission assets, and the extent to which BHE will receive added incentives on the ROE for its transmission assets, is determined by FERC along with the regional transmission owners.

BHE also has the ability to recover stranded costs of both regulatory assets and the ongoing costs of both regulatory assets and purchasing power at above-market prices. This ability eliminates the commodity risk involved with fixed price contracts. As mentioned previously, BHE has filed a request for a decrease in stranded cost rates effective Q1 2008.

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

Labour

In June 2004, Nova Scotia Power reached a 52-month agreement with 800 unionized employees, which expires in the middle of 2007.

Bangor Hydro's contract with its unionized employees expired at the end of 2005 and a new agreement has been reached, which will expire in June 2010.

Environmental Protection

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 such that risks are identified and managed proactively. All areas of Emera undertook initiatives in 2006 to reduce potential environmental risks and associated costs.

Conformance with legislative and company requirements is verified through an environmental audit program. There were no significant environmental or regulatory compliance issues identified during the 2006 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 NSPI Board of Directors' Environmental, Safety and Security Committee, as well as the Boards of all other Emera operating companies. 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.

Climate Change and Air Emissions

In October 2006 the federal government released a notice of intent to regulate air emissions and greenhouse gases under Bill C-30, Canada's Clean Air Act. The notice proposes to establish targets for air emissions consistent with standards that are substantially analogous to those in the US. It also proposes to establish targets for greenhouse gases that would reduce greenhouse gas emissions in the short term, beyond those proposed in 2005. The proposal would also achieve long-term reductions of greenhouse gases of between 45%–65% from 2003 levels by 2050. Company staff continues to work with the federal and provincial governments to develop rules that consider the potential costs and benefits to the company and its customers.

In 2006, NSPI continued to comply with annual provincial emissions limits. Plans have been developed to achieve the objectives in NSPI's Air Emissions Strategy, which addresses the entire suite of emissions, including those linked to greenhouse gases. In 2006, NSPI:

- Invested approximately $4 million to reduce oxides of nitrogen (NOx) from the Lingan plant;
- Continued to engage stakeholders and is working to develop an Integrated Resource Plan that utilizes supply-side management and demand-side options, to enable NSPI to meet future emissions and other requirements in a cost-effective and reliable manner;
- Worked with independent power producers to increase NSPI's renewable energy supply by over 60 MW, almost entirely from wind, with some biomass/landfill gas;
- In early February 2007, NSP provided notice that the company plans to issue a request for proposal for an additional 130 MWh of new renewable energy supply; and
- Continued efforts to advance research into clean energy sources and carbon dioxide storage, including the submission of an application for government funding to assist in establishing a stream tidal energy demonstration project off the coast of Nova Scotia.

SUMMARY OF QUARTERLY REPORTS

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

	Q4 2006	Q3 2006	Q2 2006	Q1 2006	Q4 2005	Q3 2005	Q2 2005	Q1 2005
Total revenues	**$ 307.0**	$ 272.4	$ 275.9	$ 310.7	$ 297.1	$ 281.1	$ 280.1	$ 309.7
Net earnings from continuing operations	**$ 33.5**	$ 19.5	$ 29.2	$ 43.6	$ 37.7	$ 18.1	$ 19.1	$ 47.2
Net earnings applicable to common shares	**$ 33.5**	$ 19.5	$ 29.2	$ 43.6	$ 37.7	$ 15.9	$ 19.3	$ 48.3
Earnings per common share – basic:								
Continuing operations	**$ 0.30**	$ 0.18	$ 0.26	$ 0.40	$ 0.34	$ 0.16	$ 0.18	$ 0.43
Discontinued operations	**–**	–	–	–	–	(0.02)	–	0.01
	$ 0.30	$ 0.18	$ 0.26	$ 0.40	$ 0.34	$ 0.14	$ 0.18	$ 0.44
Earnings per common share – diluted:								
Continuing operations	**$ 0.30**	$ 0.18	$ 0.26	$ 0.38	$ 0.34	$ 0.16	$ 0.18	$ 0.41
Discontinued operations	**–**	–	–	–	–	(0.02)	–	0.01
	$ 0.30	$ 0.18	$ 0.26	$ 0.38	$ 0.34	$ 0.14	$ 0.18	$ 0.42

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.

Management report

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The accompanying consolidated financial statements of Emera Inc. ("Emera") and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Nova Scotia Power Inc. ("NSPI"), one of Emera's wholly-owned electric utilities and principal subsidiary, is regulated by the Nova Scotia Utility and Review Board, which also examines and approves NSPI's accounting policies and practices. Emera's other wholly-owned electric utility and subsidiary, Bangor Hydro-Electric Company ("Bangor Hydro"), is regulated by the Federal Energy Regulatory Commission and the Maine Public Utilities Commission, which also examine and approve Bangor Hydro's accounting policies and practices. In preparation of these consolidated financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management believes that such estimates, which have been properly reflected in the accompanying consolidated financial statements, are based on careful judgements and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the consolidated financial statements.

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

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements. The Board carries out this responsibility principally through its Audit Committee.

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

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian generally accepted auditing standards. Ernst & Young LLP has full and free access to the Audit Committee.

February 5, 2007

Christopher Huskilson
President and Chief Executive Officer

Nancy Tower, FCA
Chief Financial Officer

Auditors' report

To the Shareholders of Emera Inc.

We have audited the consolidated balance sheets of Emera Inc. as at December 31, 2006 and 2005, and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Halifax, Canada
February 5, 2007

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants

Consolidated financial statements

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31 millions of dollars (except earnings per common share)	2006	2005
Revenue		
Electric	$ 1,132.0	$ 1,125.9
Other	34.0	42.1
	1,166.0	1,168.0
Cost of operations		
Fuel for generation and purchased power	347.7	432.0
Operating, maintenance and general	255.6	248.2
Provincial, state and municipal taxes	48.0	48.4
Provincial tax deferral (note 13)	–	(4.5)
Depreciation	145.2	136.1
Regulatory amortization	22.8	19.4
Allowance for funds used during construction	(5.8)	(4.4)
	813.5	875.2
Earnings from operations	352.5	292.8
Equity earnings (note 6)	4.9	6.5
Earnings before interest and income taxes	357.4	299.3
Interest (note 7)	127.1	117.4
Amortization of defeasance costs	12.7	13.2
Other income (note 8)	(8.9)	(8.0)
Earnings before income taxes	226.5	176.7
Income taxes (note 9)	87.4	53.5
Income taxes deferral (note 13)	–	(12.2)
Net earnings before non-controlling interest	139.1	135.4
Non-controlling interest (note 10)	13.3	13.3
Net earnings from continuing operations	125.8	122.1
Loss from discontinued operations, net of tax (note 16)	–	(0.9)
Net earnings applicable to common shares	$ 125.8	$ 121.2
Earnings per common share – basic (note 11)		
Continued operations	$ 1.14	$ 1.12
Discontinued operations	–	(0.01)
	$ 1.14	$ 1.11
Earnings per common share – diluted (note 11)		
Continued operations	$ 1.12	$ 1.10
Discontinued operations	–	(0.01)
	$ 1.12	$ 1.09

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 millions of dollars (except earnings per common share)	2006	2005
Retained earnings, beginning of year	$ 423.4	$ 399.6
Net earnings applicable to common shares	125.8	121.2
	549.2	520.8
Dividends	98.3	97.4
Retained earnings, end of year	$ 450.9	$ 423.4

See accompanying notes to the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

As at December 31 millions of dollars	2006	2005 Restated (note 2)
Assets		
Current assets		
Cash and cash equivalents	**$ 7.6**	$ 21.5
Restricted cash	**11.9**	5.8
Accounts receivable (note 12)	**253.6**	231.8
Income tax receivable	**5.3**	15.1
Inventory (note 2)	**113.6**	76.1
Prepaid expenses	**53.9**	15.9
Future income tax assets (note 9)	**18.9**	9.3
Energy marketing assets	**37.3**	16.0
	502.1	391.5
Long-term receivables (note 12)	**–**	48.4
Energy marketing assets	**2.0**	4.1
Deferred charges (note 13)	**465.4**	510.2
Future income tax assets (note 9)	**10.0**	19.0
Goodwill (note 18)	**97.1**	97.1
Investments (note 6)	**101.3**	99.1
Property, plant & equipment (note 14)	**2,756.4**	2,789.2
Construction work in progress	**125.5**	40.0
	2,881.9	2,829.2
	$ 4,059.8	$ 3,998.6
Liabilities and Shareholders' Equity		
Current liabilities		
Current portion of long-term debt (note 21)	**$ 3.4**	$ 152.9
Short-term debt (note 20)	**133.2**	88.1
Accounts payable and accrued charges	**286.0**	248.6
Income tax payable	**39.3**	1.5
Dividends payable	**3.2**	3.2
Energy marketing liabilities	**36.7**	12.1
	501.8	506.4
Energy marketing liabilities	**1.4**	2.9
Future income tax liabilities (note 9)	**86.2**	78.9
Asset retirement obligations (note 2 and note 19)	**78.1**	74.1
Deferred credits (note 13)	**66.1**	77.5
Long-term debt (note 21)	**1,657.4**	1,631.8
Non-controlling interest (note 10)	**260.7**	260.8
Shareholders' equity		
Common shares (note 22)	**1,055.2**	1,039.2
Contributed surplus (note 23)	**2.2**	1.8
Foreign exchange translation adjustment (note 25)	**(100.2)**	(98.2)
Retained earnings	**450.9**	423.4
	1,408.1	1,366.2
	$ 4,059.8	$ 3,998.6

Contingencies (note 27), Commitments (notes 5, 24 and 28), Guarantees (note 29). See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors

Derek Oland
Chairman

Christopher Huskilson
President and Chief Executive Officer

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 millions of dollars	2006	2005
Operating activities		
Net earnings before non-controlling interest	**$ 139.1**	$ 135.4
Non-cash items:		
Depreciation	**145.2**	136.1
Deferral of provincial taxes and income taxes (note 13)	**–**	(16.7)
Amortization of deferred charges	**13.9**	15.6
Equity earnings	**(4.9)**	(6.5)
Regulatory amortization	**22.8**	19.4
Allowance for funds used during construction	**(5.8)**	(4.4)
Future income taxes	**5.1**	3.3
Post-retirement benefits	**8.9**	(5.0)
Other non-cash operating items	**(1.2)**	(6.1)
Discontinued operations	**–**	1.2
Other cash operating items	**3.4**	4.9
	326.5	277.2
Change in non-cash operating working capital	**19.3**	(112.9)
Net cash provided by operating activities	**345.8**	164.3
Investing activities		
Property, plant and equipment	**(193.7)**	(129.3)
(Increase) decrease in restricted cash	**(6.1)**	11.9
Retirement spending net of salvage	**(3.2)**	(4.7)
Proceeds on disposition (note 16)	**–**	18.4
Investments	**–**	41.7
Acquisition (note 15)	**–**	(55.2)
Net cash used in investing activities	**(203.0)**	(117.2)
Financing activities		
Retirements of long-term debt	**(112.6)**	(126.7)
Issuance of long-term debt	**–**	275.9
Increase (decrease) in short-term debt	**30.5**	(143.7)
Issuance of common shares	**15.3**	20.9
Dividends on common shares	**(98.3)**	(97.4)
Dividends paid by subsidiaries to non-controlling interest	**(13.3)**	(14.1)
Long-term financing of asset sale	**20.0**	15.0
Other financing activities	**1.7**	1.8
Net cash used in financing activities	**(156.7)**	(68.3)
Decrease in cash and cash equivalents	**(13.9)**	(21.2)
Cash and cash equivalents, beginning of year	**21.5**	42.7
Cash and cash equivalents, end of year	**$ 7.6**	$ 21.5
Cash and cash equivalents consists of:		
Cash	**$ 7.2**	$ 6.9
Short-term investments	**0.4**	14.6
Cash and cash equivalents, end of year	**$ 7.6**	$ 21.5
Supplemental disclosure of cash paid:		
Interest	**$ 123.9**	$ 120.7
Income and capital taxes	**$ 45.7**	$ 61.6

See accompanying notes to the consolidated financial statements.

Notes to the consolidated financial statements

December 31, 2006 and 2005

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Emera Inc. ("Emera" or the "Company"), incorporated in the Province of Nova Scotia, through its principal subsidiaries, Nova Scotia Power Inc. ("Nova Scotia Power" or "NSPI") and Bangor Hydro-Electric Company ("Bangor Hydro" or "BHE"), is engaged in the production and sale of electric energy.

Nova Scotia Power is the primary electricity supplier in Nova Scotia providing over 95% of electricity generation, transmission and distribution in the province. NSPI is a public utility as defined under the Public Utilities Act of Nova Scotia ("Act") and is subject to regulation under the Act by the Utility and Review Board ("UARB"). The Act gives the UARB authority over NSPI's operations and expenditures. Electricity rates for NSPI's customers are subject to UARB approval. NSPI is not subject to an annual rate review process, but rather participates in hearings from time to time at NSPI's or the regulator's request.

NSPI is regulated under a cost of service model, with rates set to cover prudently incurred costs of providing electricity service to customers, and provide an opportunity to earn an appropriate return to investors. NSPI's return on equity ("ROE") range is 9.3% to 9.8%, on a maximum allowed common equity component of 40% of the total capitalization. Rates were last set using 9.55% ROE with a common equity component of 37.5%.

NSPI's accounting policies are subject to examination and approval by the UARB.

Bangor Hydro's core business is the transmission and distribution ("T&D") of electricity. Electricity is deregulated in Maine, and several suppliers compete to provide customers with the commodity that is delivered through the BHE T&D network. In addition to the T&D network, BHE has substantial net regulatory assets (stranded costs), which arose through the electricity industry restructuring, and as a result of rate and accounting orders issued by its regulators. Approximately 55% of BHE's electric rates represent distribution services, 15% relate to stranded costs recoveries, and 30% to transmission service. The rates for each element are established in distinct regulatory proceedings. The transmission operations are regulated by the Federal Energy Regulatory Commission ("FERC"), and the distribution operations and stranded costs are regulated by the Maine Public Utilities Commission ("MPUC").

For distribution services, BHE operates under an Alternate Rate Plan ("ARP"), which provides for an earnings band of 5% to 17% return on equity on distribution operations, with rates set at the midpoint of 11%. There is a 50/50 sharing mechanism between BHE and customers outside of the earnings band. The ARP also includes performance standards and provides for average annual reductions in distribution rates of approximately 2.5% for five years, to 2007.

The MPUC provides an allowed return on equity of 10% on BHE's stranded assets. BHE is required to hold stranded cost proceedings at least every three years to adjust any substantial differences in stranded cost estimates from prior periods that may arise because of differences between forecast and sales volume or the output of facilities subject to purchase power agreements.

Transmission rates are set by the FERC annually on July 1, based on the prior year's revenue requirement. The allowed ROE for transmission operations was 11.25% through October 31, 2006. As a result of a recent FERC ruling, the allowed ROE on transmission investments ranges from 10.9% for low voltage transmission up to 12.4% for high voltage transmission developed as a result of the regional system plan, which includes the NRI project.

Bangor Hydro's accounting policies are subject to examination and approval by FERC and the MPUC.

Emera follows Canadian generally accepted accounting principles ("GAAP"). The accounting policies approved by the regulators of NSPI and Bangor Hydro may differ from GAAP for non rate-regulated companies in that the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under GAAP. Where the differences between GAAP and GAAP for rate-regulated companies are considered significant, disclosure of the policy has been made in these notes to the consolidated financial statements.

a. Consolidation

The consolidated financial statements include the accounts of Emera Inc. and its subsidiaries. Intercompany transactions and accounts have been eliminated.

b. Measurement Uncertainty

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods.

At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated along with the associated unbilled revenues. This estimate is based on several different factors including generation, estimated usage by customer class, weather and line losses.

Actual results may differ from these estimates.

c. Revenue Recognition

The Company's revenue recognition policy is as follows:

- Electric: Revenues are recognized on the accrual basis, which includes an estimate of electricity consumed by customers in the year but billed subsequent to year-end.
- Energy Marketing: Derivative financial and commodity instruments that are not entered into for hedging purposes are recognized at fair market value at year-end.
- Other: Revenues are recognized on the accrual basis, which includes an estimate for services performed and goods delivered during the year but billed subsequent to year-end.
- Unearned revenue is recorded as a deferred credit.

Accounting for the impact of rate regulation:

Electric revenues generated by NSPI and Bangor Hydro are recognized at rates set by their respective regulators. The Company is unable to determine the effect on electric revenue in the absence of regulation.

d. Allowance for Funds Used during Construction

Accounting for the impact of rate regulation:

In accordance with accounting policies determined by their respective regulators, NSPI and Bangor Hydro provide for the cost of financing construction work in progress by including an allowance for funds used during construction ("AFUDC") as an addition to the cost of property constructed, using a weighted average cost-of-capital. AFUDC is included in property, plant and equipment and construction work in progress for financial reporting purposes and is charged to operations through depreciation over the service life of the related assets and recovered through future revenues. Since AFUDC includes not only an interest component, but also an equity component, it exceeds the amount that could be capitalized in the absence of the regulated accounting policies.

e. Regulatory Amortization

Accounting for the impact of rate regulation:

In accordance with the regulations of the UARB, significant assets of Nova Scotia Power, which are not currently being used and are not expected to provide service to customers in the foreseeable future, are amortized over five years. In 2000 the UARB approved NSPI's request to amortize the Glace Bay generating station over five years. The UARB had allowed Nova Scotia Power flexibility in determining the annual amount to be written off in order to support rate stability. On July 28, 2003, the UARB approved the Company's request to extend the write-off period through 2008, if necessary, with an annual minimum amortization of $6.2 million. The unamortized portion of the generation station is included in property, plant and equipment. In the absence of the UARB's approved accounting policies, the generation station would have been written off in the year when NSPI determined that the unamortized cost of the generating station would not be recoverable. More details are provided in note 14.

In accordance with rate and accounting orders issued by the MPUC, Bangor Hydro has recorded regulatory assets and liabilities on its balance sheet. These regulatory assets and liabilities are being amortized over varying lives expiring through to 2018 through charges to earnings. These regulatory assets and liabilities are included in deferred assets and deferred liabilities and include costs related to terminating/restructuring purchased power contracts, the Seabrook nuclear project, decommissioning costs for Maine Yankee, obligations to Hydro-Quebec, and the stranded cost revenue requirement levelizer, and are described in more detail in note 13.

f. Property, Plant and Equipment

Property, plant and equipment are recorded at original cost, net of contributions in aid of construction. When property, plant and equipment are replaced or retired, any remaining net book value is charged to net earnings.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The estimated average service life for the Company's unregulated general assets is six years (2005 – 11 years). Unregulated generation assets have an estimated average service life of 51 years (2005 – 51 years).

When indicators of impairment exist, the Company determines whether the net carrying amount of property, plant and equipment is recoverable from future undiscounted cash flows. Factors, which could indicate impairment exists, include significant changes in regulation, a change in the Company's strategy or underperformance relative to projected future operating results.

Accounting for the impact of rate regulation:

During 2003, following completion of a depreciation study, and a negotiated agreement with stakeholders, NSPI's regulator approved new depreciation rates which were to be phased in over four years beginning in 2004. In the decision on NSPI's 2005 rate application, the UARB delayed the phase-in of year two rates for one year. In the decision on NSPI's 2006 rate application, the UARB approved restarting of the phase-in including year two in 2006 rates. In its February 5, 2007 decision, the UARB postponed the scheduled year-three phase-in of increased depreciation rates until the next rate application. Absent consideration of growth in plant-in-service, the phase-in of new depreciation rates will increase depreciation expense by approximately $5 million per year for a cumulative increase of $20 million over the four-year period. In the absence of the UARB's approval of depreciation rates, NSPI would be required to set rates based on management's best estimates of useful lives. The average rates for the major categories of plant-in-service are summarized as follows:

Function	**2006**	2005
Generation		
Thermal	**2.44%**	2.38%
Gas turbines	**2.32%**	2.18%
Combustion turbines	**3.33%**	3.33%
Hydro-electric	**1.39%**	1.26%
Wind turbines	**5.00%**	5.00%
Transmission	**2.65%**	2.68%
Distribution	**4.04%**	3.96%
General plant	**6.55%**	5.62%
General plant under capital lease	**11.97%**	9.50%
Weighted average depreciation rate	**3.06%**	2.93%

Bangor Hydro's depreciation is determined by the straight-line method, based on the estimated service lives of the depreciable assets in each category. In 2004 BHE implemented the results of a depreciation study that was completed in 2004 and approved by its regulators. The estimated average service lives in years for the major categories of plant-in-service are summarized as follows:

Function	2006	2005
Transmission	**45**	43
Distribution	**35**	36
Other	**17**	16
Weighted average service life	**33**	32

In accordance with regulator approved accounting policies, when depreciable property, plant and equipment of NSPI and Bangor Hydro are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operation in the future through adjustments to depreciation expense. In the absence of regulator approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to net earnings as incurred.

g. Capitalization Policy

Capital assets of Nova Scotia Power and Bangor Hydro include labour, inventories, and other non-labour costs directly attributable to the capital activity. In addition, in order to ensure the full cost approach, overhead costs that contribute to the capital program are allocated to capital projects. These costs include corporate costs such as finance, information technology, executive and other support functions, and employee benefits, insurance, inventory costs, and fleet operating and maintenance costs. Nova Scotia Power and Bangor Hydro calculate an application rate and only eligible operating expenditures are used in the calculation. NSPI and BHE apply overhead costs based on direct labour costs. The application rate varies depending on the type of capital expenditure. In addition, BHE applies inventory overhead based on inventory issued to the project, and applies general and administrative overhead based upon non-labour charges.

h. Leases

Leases that substantially transfer all the benefits and risks of ownership of property, plant and equipment to the Company, or otherwise meet the criteria for capitalizing a lease under GAAP, are accounted for as capital leases. An asset is recognized at the time a capital lease is entered into together with its related long-term obligation. Property, plant and equipment recognized under capital leases are depreciated on the same basis as described in note 1(f). Payments on operating leases are expensed as incurred.

i. Income Taxes and Investment Tax Credits

Emera follows the future income tax method of accounting for income taxes.

Investment tax credits arise as a result of incurring qualifying scientific research and development expenditures and are recorded in the year as a reduction from the related expenditures where there is reasonable assurance of collection.

Accounting for the impact of rate regulation:

In accordance with ratemaking regulations established by the UARB, NSPI uses the taxes-payable method of accounting for income taxes. Bangor Hydro uses the future income tax method where allowed for ratemaking purposes. NSPI and Bangor Hydro would be required to recognize all future income tax assets and liabilities in the absence of their regulator approved accounting policies. More details are provided in note 9.

j. Employee Future Benefits

Pension obligations, and obligations associated with non-pension post-retirement benefits such as health benefits to retirees and retirement awards, are actuarially determined using the projected benefit method pro-rated on services and management's best estimate assumptions. The accrued benefit obligation is valued based on market interest rates at the valuation date.

Pension fund asset values are calculated using market values at year-end. The expected return on pension assets is determined based on market-related values. The market-related values are determined in a rational and systematic manner so as to recognize investment gains and losses, relative to the assumed rate of return, over a five-year period.

Adjustments to the accrued benefit obligation arising from plan amendments are amortized on a straight-line basis over the expected years of future service to the full eligibility date for active employees.

For any given year, when NSPI's net actuarial gain (loss), less the actuarial gain (loss) not yet included in the market-related value of plan assets, exceeds 10% of the greater of the accrued benefit obligation and the market-related value of the plan assets, an amount equal to the excess divided by the average remaining service period ("ARSP") is amortized on a straight-line basis. For NSPI, the ARSP of the active employees is 10 years as at December 31, 2006 (2005 – 10 years). For Bangor Hydro this excess is amortized on a straight-line basis over the expected ARSP, in accordance with ratemaking purposes, which is 12 years as at December 31, 2006 (2005 – 13 years).

On January 1, 2000 Emera adopted the new accounting standard on employee future benefits using the prospective application method. The transitional obligation (asset) resulting from the initial application is amortized linearly over 13 years, which was the expected ARSP of active employees at the transition date.

The difference between benefit cost and pension funding is recorded as a deferred asset or credit on the balance sheet.

k. Share-Based Compensation

The Company has several share-based compensation plans, which are a common share option plan for senior management, an employee common share purchase plan, a deferred share unit plan, and a restricted share unit plan. The Company accounts for its plans in accordance with the fair value based method of accounting for share-based compensation.

l. Cash and Cash Equivalents

Short-term investments, which consists of money market instruments with maturities of three months or less, are considered to be cash equivalents and are recorded at cost, which approximates current market value. The short-term investments have an effective interest rate of 5.23% at December 31, 2006 (2005 – 3.53%).

m. Inventory

Inventories of materials and supplies are valued at the lower of average cost and market. Fuel inventory is valued at the lower of the weighted average cost method, and net realizable value.

n. Debt Financing Costs

Financing costs pertaining to debt issues are amortized over the life of the related debt.

o. Derivative Financial & Commodity Instruments

The Company uses various derivative financial instruments to hedge its exposure to foreign exchange, interest rate, and commodity price risks. If the documentation and effectiveness requirements are met, gains and losses on these instruments are deferred and recognized in earnings in the same period the related hedged risk is realized (settlement accounting). Where documentation and effectiveness requirements are not met, the instruments are marked-to-market in the period of ineffectiveness with an adjustment to earnings.

If a hedging relationship is terminated, gains and losses on the instruments up until the date of termination are deferred and recognized in the same period the related hedged risk is realized. The instruments, if retained, would then be marked-to-market from the termination date on.

Amounts received or paid related to instruments used to hedge foreign exchange and commodity price risks are recognized in the cost of fuel purchases. Amounts received or paid, including any gains and losses on instruments used to hedge interest rate risks, are recognized over the term of the hedged item in interest expense. The derivatives are not recorded on the balance sheet.

Non-hedging derivative financial and commodity instruments are entered into and are marked-to-market at each reporting date and are reflected on the balance sheet as energy marketing assets or energy marketing liabilities. The net margin recognized is reflected in other revenue.

Derivative financial and commodity instruments are reflected in operating activities on the statement of cash flows.

Accounting for the impact of rate regulation:

In the course of implementing the provisions of Accounting Guideline 13 Hedging Relationships ("AcG-13"), NSPI determined that it could not meet the probability requirement of the standard for its derivative financial instruments in place to hedge natural gas and heavy fuel oil for its Tufts Cove generating station. This is due to the generating station's ability to fuel switch and NSPI's economic dispatch based on the cost of these two fuels. The UARB has allowed NSPI to apply hedge accounting to these derivative financial instruments as long as the other requirements of AcG-13 are met. Absent UARB approval, NSPI would be required to recognize these derivative financial instruments at fair value with any resulting changes in fair value recognized in net earnings.

p. Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the net amount of the fair values assigned to its assets and liabilities and is not subject to amortization. The Company evaluates the carrying value of goodwill for potential impairment through an annual review and analysis of fair market value. Goodwill is also evaluated for potential impairment between annual tests if an event or circumstances occur that more likely than not reduces the fair value of a business below its carrying value. Fair market value is determined by use of net present value financial models, which incorporate management's assumptions of future profitability.

q. Long-Term Investments

The Company accounts for certain investments, over which it shares control, using the proportionate consolidation method, whereby the Company recognizes its pro-rata share of the jointly controlled assets and the liabilities jointly incurred in the Company's balance sheet, recognizes its pro-rata share of any revenue and expenses in the Company's statement of earnings, and recognizes its pro-rata share of cash flows on the Company's statement of cash flows. Emera accounts for its investments in Bear Swamp and Intragas Energy using proportionate consolidation.

The Company accounts for certain investments, over which it maintains significant influence, but not control, using the equity method, whereby the amount of the investment is adjusted annually for the Company's pro-rata share of the income or loss of investment and reduced by the amount of any dividends received. Emera accounts for its investments in Maritimes & Northeast Pipeline, Maine Yankee Atomic Power Company, and Maine Electric Power Company Inc. using the equity method.

Long-term investments over which Emera does not have significant influence are accounted for on the cost basis.

r. Foreign Currency Translation

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

Assets and liabilities of self-sustaining foreign operations are translated using the exchange rates in effect at the balance sheet date and the results of operations at the average rates for the period. The resulting exchange gains and losses are deferred and included in a separate component of shareholders' equity.

s. Research and Development Costs

All research and development costs are expensed in the year incurred unless they qualify for deferral as a part of capital assets.

2. CHANGE IN ACCOUNTING POLICIES

Conditional Asset Retirement Obligations

In December 2005, the Canadian Institute of Chartered Accountants ("CICA") issued Emerging Issues Committee Abstract 159 Conditional Asset Retirement Obligations ("EIC-159"). EIC-159 is to be applied retroactively, with restatement of prior periods, to financial statements for interim and annual reporting periods ending after March 31, 2006. EIC-159 was issued in response to the diverse accounting practices that have developed under CICA Handbook Section 3110 Asset Retirement Obligations ("Section 3110") with respect to the timing of liability recognition when the timing and/or method of settlement are conditional on a future event.

As a result of adopting EIC-159, the Company has determined that it has conditional asset retirement obligations related to the disposal of polychlorinated biphenyls ("PCBs"). As at December 31, 2006, property, plant and equipment has increased by $0.5 million (2005 – $0.6 million), accumulated depreciation has decreased by $2.0 million (2005 – $1.8 million), and asset retirement obligations have increased by $2.5 million (2005 – $2.4 million). There is no impact to net earnings or retained earnings in 2006 and 2005.

Inventory

In August 2006, Nova Scotia Power changed its method of costing fuel inventory from the first-in, first-out method to the weighted average cost method to provide more appropriate information. The change in accounting policy has been approved by the UARB.

The CICA Handbook Section 1506 Accounting Changes requires that changes in accounting policies be applied retroactively to all prior periods presented for comparative purposes. Nova Scotia Power applied the change in accounting policy retroactively but did not restate prior periods as the necessary adjustments were considered immaterial. The change in accounting policy resulted in a cumulative adjustment to the opening balance of fuel inventory in Q3 2006 of $1.0 million. As a result, NSPI decreased inventory by $1.0 million and increased fuel expense by $1.0 million in Q3 2006.

3. SEGMENT INFORMATION

The Company has two reportable segments: Nova Scotia Power and Bangor Hydro. The Company evaluates performance based on contribution to consolidated net earnings applicable to common shareholders. The accounting policies of the reported segments are the same as those described in the summary of significant accounting policies.

Reported segments are determined based on Emera's operating activities. NSPI is engaged in the production and sale of electric energy in Nova Scotia; and Bangor Hydro is engaged in the transmission and distribution of electric energy in central Maine. Other revenue is largely generated from energy marketing margin and electric revenue from the Company's investment in Bear Swamp.

millions of dollars	Nova Scotia Power	Bangor Hydro	Other*	Total
Year ended December 31, 2006:				
Revenues from external customers	$ 977.5	$ 135.0	$ 53.5	$1,166.0
Depreciation	127.8	14.7	2.7	145.2
Cost of operations, including depreciation	670.4	96.6	46.5	813.5
Equity earnings	–	–	4.9	4.9
Interest expense	105.4	11.7	10.0	127.1
Other income	8.9	–	–	8.9
Income taxes	80.3	10.0	(2.9)	87.4
Net earnings applicable to common shareholders	104.3	16.8	4.7	125.8
Net inter-segment revenues/(expenses)	158.6	(3.8)	(154.8)	–
Capital expenditures	99.0	81.5	13.2	193.7
As at December 31, 2006				
Total assets	3,061.5	644.6	353.7	4,059.8
Investments subject to significant influence	–	2.7	95.8	98.5
Goodwill	–	97.1	–	97.1
Year ended December 31, 2005:				
Revenues from external customers	962.8	147.0	58.2	1,168.0
Depreciation	119.5	14.9	1.7	136.1
Cost of operations, including depreciation	722.1	110.5	42.6	875.2
Equity earnings	–	–	6.5	6.5
Interest expense	97.9	12.1	7.4	117.4
Other income	8.0	–	–	8.0
Income taxes	45.5	9.4	(1.4)	53.5
Net earnings from continuing operations	91.2	14.9	16.0	122.1
Net earnings applicable to common shareholders	91.2	14.9	15.1	121.2
Net inter-segment revenues/(expenses)	193.4	(2.7)	(190.7)	–
Capital expenditures	100.4	30.5	53.6	184.5
As at December 31, 2005				
Total assets	3,063.9	582.6	352.1	3,998.6
Investments subject to significant influence	–	3.9	92.8	96.7
Goodwill	–	97.1	–	97.1
Goodwill included in loss on disposition	–	–	7.4	7.4

*Other consists of corporate activities and adjustments to reconcile to consolidated balances.

4. EMPLOYEE FUTURE BENEFITS

Nova Scotia Power

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

Defined benefit pension plans are based on the years of service and average salary at the time the employee terminates employment and provide annual post-retirement indexing equal to the change in the Consumer Price Index up to a maximum increase of 6% per year.

Other retirement benefit plans include: unfunded pension arrangements (with same indexing formula as the funded pension arrangements), unfunded long service award (which is impacted by expected future salary levels) and contributory health care plan.

The measurement date for the assets and obligations of each benefit plan is December 31, 2006.

Valuation Date for Defined-Benefit Plans

NSPI has a December 31 valuation date for accounting purposes. The most recent and the next required actuarial valuation dates for funding purposes are as follows:

	Most recent actuarial valuation	Next required actuarial valuation
Employee pension plan	December 31, 2006	December 31, 2007
Acquired companies pension plan	December 31, 2006	December 31, 2007

Total Cash Amount

Total cash amount for 2006, made up of NSPI contributions to its funded defined-benefit pension plans, contributions to its defined-contribution pension plan, employer paid premiums for its post-retirement health care plan, and amounts paid directly to retirees and beneficiaries in other plans, was $22.8 million (2005 – $29.9 million).

Accrued Pension and Non-Pension Benefit Asset (Liability)

millions of dollars		2006 Defined-benefit pension plans	2006 Non-pension benefits plans	2005 Defined-benefit pension plans	2005 Non-pension benefits plans
Assumptions (weighted average)					
Accrued benefit obligation – December 31:					
Discount rate		**5.25%**	**5.25%**	5.25%	5.25%
Rate of compensation increase		**3.0 to 5.5%**	**3.0 to 5.5%**	3.0 to 5.5%	3.0 to 5.5%
Health care trend	– initial (next year)	**–**	**8.0%**	–	9.0%
	– ultimate	**–**	**4.0%**	–	4.0%
	– year ultimate reached	**–**	**2011**	–	2011
Benefit cost for year ending December 31:					
Discount rate		**5.25%**	**5.25%**	6.0%	6.0%
Expected long-term return on plan assets		**7.5%**	**–**	7.5%	–
Rate of compensation increase		**3.0 to 5.5%**	**3.0 to 5.5%**	3.0 to 5.5%	3.0 to 5.5%
Health care trend	– initial (current year)	**–**	**9.0%**	–	10.0%
	– ultimate	**–**	**4.0%**	–	4.0%
	– year ultimate reached	**–**	**2011**	–	2011
Accrued benefit obligations					
Balance, January 1		**$ 777.5**	**$ 34.8**	$ 640.3	$ 31.1
Employer current service cost		**12.6**	**1.3**	9.6	1.2
Employee contributions		**4.7**	**–**	4.7	–
Interest cost		**40.4**	**1.8**	38.1	1.8
Past service amendments		**–**	**2.4**	–	–
Actuarial (gains) losses		**(1.5)**	**1.9**	114.3	3.2
Benefits paid		**(31.0)**	**(2.6)**	(30.2)	(2.5)
Other		**–**	**–**	0.7	–
Balance, December 31		**802.7**	**39.6**	777.5	34.8
Fair value of plan assets					
Balance, January 1		**581.2**	**–**	516.0	–
Employer contributions		**19.6**	**2.6**	26.7	2.5
Employee contributions		**4.7**	**–**	4.7	–
Actual investment income		**82.0**	**–**	64.0	–
Benefits paid		**(31.0)**	**(2.6)**	(30.2)	(2.5)
Balance, December 31		**656.5**	**–**	581.2	–
Reconciliation of financial status to accrued benefit asset, December 31					
Fair value of plan assets		**656.5**	**–**	581.2	–
Accrued benefit obligations		**802.7**	**39.6**	777.5	34.8
Plan deficit		**(146.2)**	**(39.6)**	(196.3)	(34.8)
Unamortized past service (gains) costs		**(0.5)**	**2.3**	(0.6)	–
Unamortized actuarial losses (gains)		**213.2**	**0.6**	273.5	(1.6)
Unamortized transitional obligation		**0.1**	**13.4**	0.1	15.7
Accrued benefit asset (liability)		**$ 66.6**	**$ (23.3)**	$ 76.7	$ (20.7)

The expected return on plan assets is determined based on the market-related value of plan assets of $578.1 million at January 1, 2006 (2005 – $550.9 million), adjusted for interest on certain cash flows during the year.

Defined Benefit Plans Asset Allocation

% of plan assets	2006 Employee pension plan	2006 Acquired companies pension plan	2005 Employee pension plan	2005 Acquired companies pension plan
Equity securities	**69%**	**62%**	66%	60%
Debt securities	**29%**	**37%**	33%	37%
Cash	**2%**	**1%**	1%	3%
Total	**100%**	**100%**	100%	100%

As at December 31, 2006, the pension funds do not hold any material investments in Emera Inc. or Nova Scotia Power Inc. securities. Any such investment would primarily be held indirectly through pooled investment funds.

Plans with Accrued Benefit Obligations in Excess of Assets

As at December 31, 2006, all post-retirement benefit plans have accrued benefit obligations in excess of assets.

Benefits Cost Components

millions of dollars	2006 Defined-benefit pension plans	2006 Non-pension benefits plans	2005 Defined-benefit pension plans	2005 Non-pension benefits plans
Defined benefit plan				
Costs arising from events during the year:				
Current service costs	**$ 12.6**	**$ 1.3**	$ 9.6	$ 1.2
Interest on accrued benefits	**40.4**	**1.8**	38.1	1.8
Less: actual return on plan assets	**(82.0)**	**–**	(64.0)	–
Actuarial (gains) losses on accrued benefit obligation	**(1.5)**	**1.9**	114.3	3.2
Past service costs	**–**	**2.3**	–	–
Other	**–**	**–**	0.7	–
Future benefit costs before adjustments	**(30.5)**	**7.3**	98.7	6.2
Adjustments to recognize long-term nature of costs:				
Difference between expected return on assets and actual return	**38.9**	**–**	23.0	–
Amortization of transitional obligation	**–**	**2.3**	–	2.2
Difference between amortization of actuarial losses (gains) and actual actuarial losses (gains) on accrued benefit obligations	**21.4**	**(2.0)**	(105.1)	(3.6)
Difference between amortization of past service costs and past service costs for the year	**–**	**(2.4)**	–	–
Total cost recognized	**$ 29.8**	**$ 5.2**	$ 16.6	$ 4.8
Defined contribution plan				
Employer cost	**$ 0.7**	**–**	$ 0.7	–

Sensitivity Analysis for Non-Pension Benefits Plans

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2006:

millions of dollars	Increase	Decrease
Current service cost and interest cost	$ 0.2	$ (0.2)
Accrued benefit obligation, December 31	$ 2.1	$ (1.7)

Bangor Hydro

BHE maintains a non-contributory defined-benefit and a contributory defined-contribution pension plan, which cover substantially all of its employees, and a health care plan for its retirees. The defined benefit pension is based on the years of service and average salary at the time the employee terminates employment and provides no post-employment indexing. The defined-benefit pension plan was closed to new entrants effective February 2006.

Other retirement benefit plans include an unfunded pension arrangement and a contributory health care plan.

The measurement date for the assets and obligations of each benefit plan is December 31, 2006.

Valuation Date for Defined-Benefit Plans

BHE has a December 31 valuation date for accounting purposes. The most recent and the next required actuarial valuation dates for funding purposes are the following:

	Most recent actuarial valuation	Next required actuarial valuation
Employee pension plan	December 31, 2005	December 31, 2006

Total cash amount

Total cash amount for 2006, made up of BHE contributions to its funded defined-benefit pension plan, contributions to its defined contribution pension plan, employer paid premiums for its post-retirement health care plan, and amounts paid directly to retirees and beneficiaries in other plans, was $10.7 million (2005 – $5.3 million).

Accrued Pension and Non-Pension Benefit Liability

millions of dollars	2006 Defined-benefit pension plans	2006 Non-pension benefit plans	2005 Defined-benefit pension plans	2005 Non-pension benefit plans
Assumptions (weighted average)				
Accrued benefit obligation – December 31:				
Discount rate	**6.00%**	**6.00%**	5.75%	5.75%
Rate of compensation increase	**4.00%**	**4.00%**	4.00%	4.00%
Health care trend – initial (next year)	**–**	**8.40%**	–	9.20%
– ultimate	**–**	**5.00%**	–	5.00%
– year ultimate reached	**–**	**2011**	–	2011
Benefit cost for year ending December 31:				
Discount rate	**5.75%**	**5.75%**	6.00%	6.00%
Expected long-term return on plan assets	**8.00%**	**5.00%**	8.00%	5.00%
Rate of compensation increase	**4.00%**	**4.00%**	4.00%	4.00%
Health care trend – initial (current year)	**–**	**9.20%**	–	10.80%
– ultimate	**–**	**5.00%**	–	5.00%
– year ultimate reached	**–**	**2011**	–	2010
Accrued benefit obligations				
Balance, January 1	**$ 85.8**	**$ 35.6**	$ 86.8	$ 33.9
Employer current service cost	**1.5**	**0.7**	1.6	0.8
Interest cost	**4.7**	**1.8**	5.0	2.2
Past service amendments	**(0.3)**	**–**	–	(5.0)
Actuarial (gains) losses	**(3.2)**	**1.9**	0.1	7.3
Benefits paid	**(4.3)**	**(2.3)**	(4.6)	(2.5)
Foreign currency translation adjustment	**(0.2)**	**0.1**	(3.1)	(1.1)
Balance, December 31	**84.0**	**37.8**	85.8	35.6
Fair value of plan assets				
Balance, January 1	**50.6**	**1.0**	51.0	1.1
Employer contributions	**8.2**	**2.3**	2.7	2.4
Actual investment income	**5.2**	**–**	3.1	–
Benefits paid	**(4.3)**	**(2.3)**	(4.6)	(2.4)
Foreign currency translation adjustment	**0.2**	**0.2**	(1.6)	(0.1)
Balance, December 31	**59.9**	**1.2**	50.6	1.0
Reconciliation of financial status to accrued benefit asset, December 31				
Fair value of plan assets	**59.9**	**1.2**	50.6	1.0
Accrued benefit obligations	**84.0**	**37.8**	85.8	35.6
Plan deficit	**(24.1)**	**(36.6)**	(35.2)	(34.6)
Unamortized past service costs (gains)	**1.5**	**(4.4)**	2.1	(4.8)
Unamortized actuarial losses	**18.4**	**10.8**	24.0	9.7
Unamortized transitional obligation	**–**	**3.5**	–	4.1
Accrued benefit liability	**$ (4.2)**	**$ (26.7)**	$ (9.1)	$ (25.6)

For the defined benefit pension plan, the expected return on plan assets is determined based on the market-related value of plan assets of $51.9 million at January 1, 2006 (January 1, 2005 – $52.8 million), adjusted for interest on certain cash flows during the year.

Defined Benefit Plans Asset Allocation

% of plan assets	2006	2005
	Employee pension plan	Employee pension plan
Equity securities	**59%**	62%
Debt securities	**40%**	37%
Other	**1%**	1%
Total	**100%**	100%

As at December 31, 2006, the pension fund does not directly hold any investments in Emera or Bangor Hydro securities. However, as a significant portion of assets for the benefit plans are held in mutual funds, there may be indirect investments in these securities.

Plans with Accrued Benefit Obligation in Excess of Assets

As at December 31, 2006, all post-retirement benefit plans have accrued pension obligations in excess of assets.

Benefits Cost Components

	2006		2005	
millions of dollars	Defined-benefit pension plans	Non-pension benefit plans	Defined-benefit pension plans	Non-pension benefit plans
Defined benefit plan				
Costs arising from events during the year:				
Current service costs	**$ 1.5**	**$ 0.7**	$ 1.6	$ 0.8
Interest on accrued benefits	**4.7**	**1.8**	5.0	2.2
Less: actual return on plan assets	**(5.2)**	**–**	(3.1)	–
Actuarial (gains) losses on accrued benefit obligation	**(3.2)**	**1.9**	0.1	7.3
Past service gains	**(0.3)**	**–**	–	(5.0)
Future benefit costs before adjustments	**(2.5)**	**4.4**	3.6	5.3
Adjustments to recognize long-term nature of costs:				
Difference between expected return on assets and actual return	**1.0**	**–**	(1.2)	–
Amortization of transitional obligation	**–**	**0.6**	–	0.6
Difference between amortization of actuarial losses (gains) and actual actuarial losses (gains) on accrued benefit obligations	**4.5**	**(1.1)**	0.9	(6.6)
Difference between amortization of past service costs and past service costs for the year	**0.6**	**(0.5)**	0.4	5.0
Total cost recognized	**$ 3.6**	**$ 3.4**	$ 3.7	$ 4.3
Defined contribution plan				
Employer cost	**$ 0.2**	**–**	$ 0.2	–

Sensitivity Analysis for Non-Pension Benefits Plans

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2006:

millions of dollars	Increase	Decrease
Current service cost and interest cost	$ 0.6	$ (0.3)
Accrued benefit obligation, December 31	$ 6.5	$ (5.1)

Accounting for the impact of rate regulation:

When Bangor Hydro was purchased by Emera, BHE received regulatory approval to continue amortizing certain existing schedules over a period of 10 years. Under GAAP, as a result of the purchase, these unamortized balances would have been recognized immediately in the year BHE was purchased. In the absence of the regulatory policy, BHE's total accrued benefit liability would be $47.1 million (2005 – $53.0 million) and the total defined benefits expense for 2006 would be $4.8 million (2005 – $5.8 million).

5. OPERATING LEASES

The Company has entered into operating lease agreements for office space, telecommunication services, and certain other equipment, which expire in 2007 to 2020. Future minimum annual lease payments under the leases are as follows:

millions of dollars	
2007	$ 7.4
2008	6.7
2009	6.2
2010	4.9
2011	1.5
Thereafter	2.9
	$ 29.6

For the year ended December 31, 2006 the Company recognized $7.1 million (2005 – $6.2 million) in operating, maintenance and general expense.

6. INVESTMENTS AND EQUITY EARNINGS

Investments are comprised of the following:

		2006		2005
millions of dollars	**Carrying value**	**Equity earning**	Carrying value	Equity earnings
Equity accounted investments				
Maritimes & Northeast Pipeline	**$ 95.8**	**$ 4.9**	$ 92.8	$ 6.5
Maine Yankee Atomic Power Company	**1.4**	**–**	2.4	–
Maine Electric Power Company Inc.	**1.3**	**–**	1.5	–
Total equity investments	**98.5**	**4.9**	96.7	6.5
Long-term portfolio investments	**2.8**	**–**	2.4	–
	$ 101.3	**$ 4.9**	$ 99.1	$ 6.5

7. INTEREST

Interest expense consists of the following:

millions of dollars	2006	2005
Interest on long-term debt	$ 104.4	$ 104.8
Interest on short-term debt	16.5	14.6
Amortization of debt financing	1.8	1.9
Foreign exchange losses (gains)	4.4	(3.9)
	$ 127.1	$ 117.4

8. OTHER INCOME

During 2006, Nova Scotia Power received an $8.9 million insurance settlement on a petcoke supply interruption claim related to 2005.

During 2005, Nova Scotia Power received a payment of $10.5 million, less $2.5 million of associated costs, from a gas supplier as part of renegotiations and resolution of certain contractual matters.

9. INCOME TAXES

The income tax provision differs from that computed using the statutory rates for the following reasons:

millions of dollars		2006		2005
Earnings before income taxes	$ 226.5		$ 176.7	
Income taxes, at statutory rates	86.3	38.1%	67.4	38.1%
Unrecorded future income taxes on regulated earnings	4.2	1.9	(10.8)	(6.1)
Equity earnings not subject to tax	(1.9)	(0.8)	(2.7)	(1.5)
Large corporations tax	–	–	4.2	2.4
Other	(1.2)	(0.6)	(4.6)	(2.6)
	87.4	38.6%	53.5	30.3%
Income taxes – current	82.3		50.2	
Income taxes – future	$ 5.1		$ 3.3	

The future income tax assets and liabilities comprise the following:

millions of dollars	Current portion 2006	Current portion 2005	Long-term portion 2006	Long-term portion 2005
Future income tax assets:				
Tax loss carry forwards	**$ 15.1**	$ 7.8	**$ 6.5**	$ 14.6
Property, plant and equipment	**–**	–	**1.6**	3.2
Other	**3.8**	1.5	**1.9**	1.2
	$ 18.9	$ 9.3	**$ 10.0**	$ 19.0

millions of dollars	Long-term portion 2006	Long-term portion 2005
Future income tax liabilities:		
Property, plant and equipment	**$ 85.9**	$ 80.0
Deferred charges	**12.1**	16.6
Deferred credits	**(7.9)**	(10.8)
Tax loss carry forwards	**(4.1)**	(2.6)
Financing	**–**	(4.2)
Other	**0.2**	(0.1)
	$ 86.2	$ 78.9

As at December 31, 2006, the Company has tax losses of $67.9 million, which are reflected in future income tax assets or netted against future income liabilities as appropriate, and expire as follows:

millions of dollars	
2008	$ 0.9
2009	3.6
2010	10.8
Thereafter	52.6
	$ 67.9

Accounting for the impact of rate regulation:

At December 31, 2006, the unrecorded future income tax assets of NSPI are approximately $34.0 million (2005 – $21.2 million), consisting of deductible temporary differences of $97.1 million (2005 – $55.7 million). In the absence of the UARB's approval of NSPI's taxes payable accounting policy, NSPI would have had a future income tax recovery of $12.8 million in 2006 (2005 – $18.0 million income tax expense).

10. NON-CONTROLLING INTEREST

The non-controlling interest consists of the preferred shares of Nova Scotia Power Inc. and Bangor Hydro-Electric Company. Dividends on the preferred shares and related taxes are reflected in non-controlling interest expense.

Non-controlling interest expense consists of preferred share dividends less a net recovery of income tax expense of $0.8 million (2005 – $0.8 million). The income tax recovery of $6.4 million in 2006 (2005 – $6.4 million) is reflected as a reduction of preferred share dividends with an offsetting increase in income tax expense.

millions of dollars	2006	2005
Preferred share dividend	**$ 14.1**	$ 14.1
Part VI.1 tax on preferred share dividends	**5.6**	5.6
Part I tax recovery related to the Part VI.1 tax deduction	**(6.4)**	(6.4)
	$ 13.3	$ 13.3

11. EARNINGS PER SHARE

Earnings per share for 2006 are as follows:

				2006
		Net earnings (millions of dollars)	**Weighted average common shares (millions)**	**EPS ($)**
Basic EPS	**$**	**125.8**	**110.5**	**$ 1.14**
Series C preferred shares of NSPI		**5.8**	**6.2**	**(0.01)**
Series D preferred shares of NSPI		**7.5**	**6.7**	**–**
Restricted share units and deferred share units		**–**	**0.5**	**(0.01)**
Diluted EPS	**$**	**139.1**	**123.9**	**$ 1.12**

Senior management share options, whose exercise price exceeded the average market price for the period, were excluded from the above calculation because they did not dilute earnings per share.

Earnings per share for 2005 are as follows:

				2005
		Net earnings (millions of dollars)	Weighted average common shares (millions)	EPS ($)
Basic EPS	$	121.2	109.5	$ 1.11
Series C preferred shares of NSPI		5.8	6.6	(0.01)
Series D preferred shares of NSPI		7.5	7.1	(0.01)
Diluted EPS	$	134.5	123.2	$ 1.09

Restricted share units and deferred share units, and senior management share options, whose exercise price exceeded the average market price for the period, were excluded from the above calculation because they did not dilute earnings per share.

12. ACCOUNTS RECEIVABLE

In May 2004 NSPI renewed a revolving non-recourse securitization agreement with an independent trust administered by a major Canadian bank. Under the securitization agreement NSPI sells an undivided co-ownership interest in certain current and future accounts receivable generated in the normal course of business. The amount of the accounts receivables sold is removed from the balance sheet with each revolving securitization. NSPI also retains an undivided co-ownership of approximately 10% in the receivables sold to the trust. The retained interest is accounted for at carrying value in deferred charges. Fees related to securitization are expensed as incurred.

At December 31, 2006, net accounts receivables sold amounted to $80 million (2005 – $80 million). This agreement is in place until 2009 with the intention that it will be renewed at that time.

At December 31, 2006, the Company had unbilled revenue included in accounts receivable in the amount of $82.3 million (2005 – $71.8 million). The unbilled revenue is an estimate of the amount of revenue related to energy delivered to customers since the date their meter was last read. Actual results may differ from this estimate.

NSPI's existing long-term 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, to be settled in November 2007. Management's best estimate of the price rebate, based on the contract specifications using actual and forward market pricing, of $68.9 million (2005 – $48.4 million) is reflected in accounts receivables. In 2005, this receivable was classified in long-term receivables.

13. DEFERRED CHARGES AND CREDITS

Deferred charges and credits, including the impact of rate-regulated accounting policies, include the following:

millions of dollars	2006	2005
Deferred charges:		
Regulatory assets:		
Pre-2003 income tax liability and related interest	**$ 147.1**	$ 146.7
Unamortized defeasance costs	**143.8**	156.5
Costs to terminate/restructure purchased power contracts	**23.2**	28.0
Seabrook nuclear project	**17.6**	19.6
Deferral of income and capital taxes not included in Q1 2005 rates	**16.7**	16.7
Maine Yankee decommissioning costs	**14.0**	19.7
Stranded cost revenue requirement levelizers	**10.1**	13.3
Deferred restructuring costs	**7.4**	8.7
Hydro-Quebec obligation	**4.5**	5.2
Other	**8.0**	6.9
	392.4	421.3
Non-regulatory assets:		
Accrued pension and non-pension benefit asset (note 4)	**43.3**	56.0
Unamortized debt financing costs	**13.0**	14.7
Retained interest in accounts receivable securitized (note 12)	**8.1**	7.6
Other	**8.6**	10.6
	73.0	88.9
	$ 465.4	$ 510.2
Deferred credits:		
Regulatory liabilities:		
Other	**$ 2.2**	$ 3.4
	2.2	3.4
Non-regulatory liabilities:		
Accrued pension and non-pension benefit liability (note 4)	**30.9**	34.7
Maine Yankee decommissioning liability	**14.0**	19.7
Hydro-Quebec obligation	**4.5**	5.2
Unearned revenue	**3.1**	5.0
Other	**11.4**	9.5
	63.9	74.1
	$ 66.1	$ 77.5

Regulatory assets consist of:

Pre-2003 Income Tax Liability and Related Interest

NSPI has a regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers. This circumstance arose when NSPI claimed capital cost allowance ("CCA") deductions in its income tax returns that were ultimately disallowed by a decision of the Supreme Court of Canada. NSPI applied to the regulator to include recovery of these costs in customer rates. In its February 5, 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007. In the absence of UARB approved recovery, the liability would have been expensed when incurred.

Unamortized Defeasance Costs

Upon privatization in 1992, NSPI became responsible for managing a portfolio of approximately $1.05 billion of defeasance securities held in trust. The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB. In the absence of UARB approval, the losses would have been expensed as incurred and net earnings would be $12.7 million higher in 2006 (2005 – $13.2 million).

Costs to Terminate/Restructure Purchased Power Contracts

Bangor Hydro has power purchase contracts, which it was required to negotiate when oil prices were high, with several independent power producers known as small power production facilities. The cost of power from these facilities is more than Bangor Hydro would incur from other sources if it were not obligated under these contracts. Bangor Hydro has been attempting to alleviate the adverse impact of these high-cost contracts and in doing so has incurred costs to terminate or restructure certain of the contracts. The MPUC has allowed Bangor Hydro to defer these costs and recover them in stranded cost rates. The contract termination was recovered over an 11-year period, which ended in February 2006, while the contract restructuring is being recovered over a 20-year period ending in June 2018. The annual amortization is approximately $4.6 million, beginning in 2006. In the absence of the MPUC's approval, these costs would have been expensed as incurred and earnings would have been $4.6 million ($2.7 million after-tax) higher in 2006 (2005 – $19.4 million or $11.7 million after-tax).

Seabrook Nuclear Project

Bangor Hydro was a participant in the Seabrook nuclear project in Seabrook, New Hampshire. On December 31, 1984, Bangor Hydro had almost $87 million invested in Seabrook, but because the uncertainties arising out of the Seabrook Project were having an adverse impact on Bangor Hydro's financial condition, an agreement for the sale of Seabrook was reached in mid-1985 and was consummated in November 1986. In 1985, the MPUC issued an order disallowing recovery of certain Seabrook costs, but provided for the recovery through customer rates of 70% of Bangor Hydro's year-end 1984 investment in Seabrook Unit 1 over 30 years ending in October 2015. In the absence of MPUC approval, the loss on sale would have been recognized when incurred and earnings for 2006 would be $1.9 million ($1.1 million after-tax) higher (2005 – $2.1 million or $1.2 million after-tax).

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

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. In 2005, NSPI deferred $16.7 million consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes, reflecting increases in these taxes since rates were last set in 2002. In its February 5, 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007. In the absence of the UARB's approval, these taxes would not have been deferred and net earnings would have been $16.7 million lower in 2005.

Maine Yankee Decommissioning Costs

Bangor Hydro owns 7% of the common stock of Maine Yankee, which in 1997 permanently shut down its nuclear generating plant. Pursuant to a contract with Maine Yankee, BHE is required to pay its pro-rata share of Maine Yankee's operating expenses including decommissioning costs. BHE's share of the estimated decommissioning costs were approximately $4.7 million in 2006 (2005 – $5.0 million). Maine Yankee expense recovery is included in BHE's stranded cost revenues, and along with all stranded cost revenues, purchased power, and Hydro-Quebec costs, are fully recoverable starting March 1, 2005. For any variance between the actual amount of these items and the amounts used in setting rates, a regulatory deferral is recorded with a credit or charge to regulatory amortizations. Any over or under-recovery will be reviewed at future rate proceedings with the MPUC. In the absence of regulator approval, the Maine Yankee decommissioning costs would have been expensed when incurred and earnings would have been $4.7 million ($2.8 million after-tax) higher in 2006 (2005 – $5.0 million or $3.0 million after-tax).

Stranded Cost Revenue Requirement Levelizer

Bangor Hydro's current stranded cost rates are designed to recover their cumulative stranded cost revenue requirements over a three-year period from March 2005 to February 2008. While the stranded cost revenue requirements differ throughout the period due to changes in purchased power expenses and varying amortization periods for regulatory assets and liabilities, the annual stranded cost revenues are the same during the period. To levelize the impact of the varying revenue requirements, cost or revenue deferrals are recognized. For the period March 2005 to February 2006 BHE deferred $15.0 million of costs and will amortize the deferral almost evenly over the periods March 2006 to February 2007, and March 2007 to February 2008. This levelizer is recognized only as result of regulatory accounting and the stranded cost ratemaking process. Absent regulatory accounting, the levelizer mechanism would not exist, and the methodology for determining BHE's rates associated with stranded costs is not known. In the absence of regulatory approval, earnings for 2006 would be $3.9 million ($2.3 million after-tax) higher (2005 – $13.9 million lower or $8.4 million after-tax).

Deferred Restructuring Costs

In order to provide rate stability, the UARB allows NSPI to defer the cost of large early retirement and severance programs, and amortize the resulting deferred charges on a straight-line basis over a three-year period, commencing in the period in which the program is initiated.

In conjunction with Bangor Hydro's Alternative Rate Plan, BHE has been provided with accounting orders from the MPUC to defer and amortize over ten years certain employee transition costs. Eligible for deferral are the 2002 and 2003 employee transition costs related to reductions in the cost of operations and employee transition costs associated with Bangor Hydro's automated meter reading project and the outsourcing of information technology support in 2004 and 2005.

In the absence of regulator approval, these costs would have been expensed as incurred and 2006 earnings would be $1.3 million ($0.8 million after-tax) higher (2005 – $2.1 million or $2.0 million after-tax).

Hydro-Quebec Obligation

The obligation associated with Hydro-Quebec represents the estimated present value of Bangor Hydro's estimated future payments for net costs associated with ownership and operation of the Hydro-Quebec intertie between the New England utilities and Hydro-Quebec. The obligation has been recognized as a long-term deferred credit, and the MPUC has permitted recovery of this obligation. The regulatory asset and obligation are being reduced as expenses are incurred with the reduction of the regulatory asset amortized to purchase power expense. In the absence of regulator approval, 2006 earnings would be $0.5 million ($0.3 million after-tax) higher (2005 – $0.5 million or $0.3 million after-tax).

Other

Bangor Hydro has other regulatory assets, which are being amortized to net earnings over varying lives. These deferred costs would have been expensed as incurred in the absence of approval from one of its regulators, and earnings would have been $2.7 million ($1.6 million after-tax) higher in 2006 (2005 – $4.1 million or $2.4 million after-tax).

Regulatory liabilities include:

Other

Bangor Hydro has other regulatory liabilities, which are being amortized to net earnings over varying lives. These deferred gains would have been expensed as incurred in the absence of approval from one of its regulators, and earnings would have been $1.2 million ($0.7 million after-tax) lower in 2006 (2005 – $0.9 million or $0.6 million after-tax).

14. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

			2006
millions of dollars	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Generation			
Thermal	**$ 1,744.0**	**$ 676.7**	**$ 1,067.3**
Gas Turbines	**32.1**	**21.8**	**10.3**
Combustion Turbines	**76.7**	**13.2**	**63.5**
Hydro-electric	**434.6**	**129.5**	**305.1**
Wind Turbines	**2.1**	**0.4**	**1.7**
Transmission	**683.5**	**315.6**	**367.9**
Distribution	**1,324.1**	**611.7**	**712.4**
Other	**382.0**	**157.1**	**224.9**
Other, under capital lease	**3.8**	**0.5**	**3.3**
	$ 4,682.9	**$ 1,926.5**	**$ 2,756.4**

			2005 Restated (note 2)
millions of dollars	Cost	Accumulated Depreciation	Net Book Value
Generation			
Thermal	$ 1,719.1	$ 634.1	$ 1,085.0
Gas Turbines	31.1	21.5	9.6
Combustion Turbines	76.5	10.5	66.0
Hydro-electric	427.6	123.4	304.2
Wind Turbines	2.0	0.3	1.7
Transmission	673.4	300.1	373.3
Distribution	1,285.3	571.2	714.1
Other	371.6	137.2	234.4
Other, under capital lease	0.9	–	0.9
	$ 4,587.5	$ 1,798.3	$ 2,789.2

Accounting for the impact of rate regulation:

At December 31, 2006, the Glace Bay generating station had a net book value of $5.1 million (2005 – $12.9 million). During the year NSPI amortized $8.6 million (2005 – $6.2 million) related to the plant, and capitalized $0.8 million in AFUDC (2005 – $1.3 million) to the plant value. In the absence of the UARB's approved accounting policies, the generation station would have been written off in the year when NSPI determined that the unamortized cost of the generating station would not be recoverable.

15. ACQUISITION

On May 24, 2005 Emera and Brookfield Power Corporation (formerly Brascan Power Corporation), in a 50/50 joint venture, acquired Bear Swamp, a 600 megawatt ("MW") pumped storage hydro-electric facility in northern Massachusetts. Emera's share of the purchase price was $61.2 million. The facility sells energy, capacity and ancillary products to the New England Power Pool. Also included in the acquisition is the nearby 10 MW Fife Brook run-of-river hydro-electric facility.

The acquisition has been accounted for under the purchase method of accounting using proportionate consolidation, and accordingly, Emera's pro-rata share of the results of operations since the date of acquisition have been included in the consolidated statement of earnings.

Emera's share of the transaction is summarized as follows:

Net assets acquired		million of dollars
Inventory	$	0.2
Property, plant and equipment		61.8
Deferred charges		0.2
Accrued liabilities		(0.1)
Deferred credits		(0.9)
Total cash consideration	$	61.2

16. DISCONTINUED OPERATIONS AND DISPOSAL OF LONG-LIVED ASSETS

Effective September 30, 2005 Emera Fuels, a subsidiary of Emera, sold its heating oil distribution business. Emera Fuels is included in the segment "Other" in note 3 Segment Information.

Emera Fuels has been accounted for as discontinued operations. Accordingly, prior periods have been reclassified to reflect this change. The following provides additional information with respect to amounts included in loss from discontinued operations on the consolidated statements of earnings:

millions of dollars		2005
Revenue	$	69.7
Earnings before income taxes	$	0.3
Loss on disposition, net of tax	$	(1.6)

The following summarizes the transaction:

millions of dollars		
Cash proceeds on disposition	$	18.6
Disposition costs		0.2
Net cash proceeds on disposition		18.4
Net assets included in disposition		19.3
Loss on disposition		0.9
Income taxes		0.7
Loss on disposition, net of tax	$	1.6

17. INTEREST IN JOINT VENTURES

The following amounts represent the Company's proportionate interest in its joint ventures' financial position, operating results, and cash flows included in the consolidated financial statements:

millions of dollars	2006	2005
Current assets	**$ 8.1**	$ 3.3
Non-current assets	**58.7**	59.3
	$ 66.8	$ 62.6
Current liabilities	**$ 4.9**	$ 3.4
Non-current liabilities	**0.1**	–
	$ 5.0	$ 3.4
Revenues	**$ 30.5**	$ 26.6
Expenses	**(28.0)**	(24.1)
Net earnings	**$ 2.5**	$ 2.5
Cash (used in) provided by operations	**$ (1.2)**	$ 7.0
Cash used in investing activities	**(0.7)**	(62.6)
Cash provided by financing activities	**0.1**	57.5
(Decrease) increase in cash	**$ (1.8)**	$ 1.9

18. GOODWILL

The change in goodwill is due to the following:

millions of dollars	2006	2005
Balance, beginning of year	**$ 97.1**	$ 107.7
Disposition of Emera Fuels	**–**	(7.4)
Change in foreign exchange rate	**–**	(3.2)
Balance, end of year	**$ 97.1**	$ 97.1

19. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations are recognized when incurred and represent the fair value, using the Company's credit-adjusted risk-free rate, of the Company's estimated future cash flows necessary to discharge legal obligations related to reclamation of land at the Company's thermal, hydro and combustion turbine sites, and disposal of PCBs in its transmission and distribution equipment. Estimated future cash flows are based on the Company's completed depreciation studies, prior experience, estimated useful lives, and governmental regulatory requirements. Actual results may differ from these estimates.

The change in asset retirement obligations is due to the following:

millions of dollars	**2006**	2005 Restated (note 2)
Balance, beginning of year	**$ 74.1**	$ 70.8
Accretion included in depreciation expense	**2.0**	0.9
Accretion deferred to regulatory asset	**2.1**	2.8
Liabilities settled	**(0.1)**	–
Disposition of Emera Fuels	**–**	(0.2)
Other	**–**	(0.2)
Balance, end of year	**$ 78.1**	$ 74.1

The key assumptions used to determine the asset retirement obligations are as follows:

Asset	Credit-adjusted risk-free rate	Estimated undiscounted future obligation millions of dollars	Expected settlement date
Thermal	5.3%	$ 242.3	14–33 years
Hydro	5.3%	60.8	25–55 years
Combustion Turbines	5.3%	5.1	1–17 years
Transmission & Distribution	5.3%	7.2	1–19 years
Other	7.4%–8.6%	0.5	4–9 years
		$ 315.9	

Some of the Company's hydro, transmission and distribution assets may have additional asset retirement obligations. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligation cannot be made at this time.

Accounting for the impact of rate regulation:

Any difference between the amount approved by the regulator of Nova Scotia Power as depreciation expense and the amount that would have been calculated under the accounting standard for asset retirement obligations is recognized as a regulatory asset in property, plant and equipment. In the absence of this deferral, net earnings for 2006 would be $2.1 million lower (2005 – $2.8 million).

20. SHORT-TERM DEBT

For the year ended December 31, 2006, short-term debt consists of:

- LIBOR loans of $122.1 million issued against lines of credit. LIBOR loans bear interest at prevailing market rates, which on December 31, 2006, averaged 5.94%.
- Advances of $11.1 million against the operating line of credit, which when drawn upon, bears interest at the prime rate, which on December 31, 2006, was 6.00%.

This short-term debt is unsecured.

For the year ended December 31, 2005, short-term debt consists of:

- LIBOR loans of $58.1 million issued against lines of credit. LIBOR loans bear interest at prevailing market rates, which on December 31, 2005, averaged 4.93%.
- Advances of $5.4 million against the operating line of credit, which when drawn upon, bears interest at the prime rate, which on December 31, 2005, was 5.00%.
- Bangor Hydro borrowings under its revolving credit loan agreement of $21.1 million that bears interest at 5.1%.
- Emera Energy Services' US base rate loan for $3.5 million that bears interest at 7.25% (US prime).

This short-term debt is unsecured.

21. LONG-TERM DEBT

Long-term debt includes the issues detailed below. All long-term debt instruments are issued under trust indentures at fixed interest rates, and are unsecured unless noted below. Also included are certain bankers acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year.

	Effective Average Interest Rate %			Amount Outstanding	
millions of dollars	**2006**	2005	Years of Maturity	**2006**	2005
Emera					
Bankers Acceptances and Advances	**5.23**	–	**1 year renewal**	**$ 111.0**	–
Medium Term Notes	**–**	6.000	**–**	**–**	$ 100.0
Private Placement – secured by a letter of credit	**–**	6.297	**–**	**–**	10.0
NSPI					
Medium Term Notes	**6.64**	6.61	**2008-2097**	**1,250.0**	1,250.0
Debentures	**9.75**	9.75	**2019**	**95.0**	95.0
Commercial paper	**4.29**	3.02	**1 year renewal**	**57.0**	182.0
Capital lease obligations	**4.44**	4.41	**2013**	**3.8**	0.9
Bangor Hydro (issued and payable in US$)					
General & Refunding Mortgage Bonds – secured by first mortgage indentures	**9.74**	9.74	**2020-2022**	**58.3**	58.3
Municipal Review Committee	**5.00**	5.00	**2007-2008**	**4.1**	6.9
Senior unsecured note	**6.09**	6.09	**2012**	**23.3**	23.3
Senior unsecured notes	**5.31**	5.31	**2008-2018**	**58.3**	58.3
				1,660.8	1,784.7
Less: Amount due within one year				**3.4**	152.9
				$ 1,657.4	$ 1,631.8

An NSPI medium term note ("MTN") of $40.0 million bearing interest at 5.20%, maturing in 2029, was redeemable at the option of the holder in 2006. None of this issue was redeemed and the interest rate on the MTN is 6.28% until maturity. Another NSPI MTN of $40.0 million, maturing in 2026, is extendable until 2056 at the option of the holder.

As at December 31, 2006 long-term debt and obligations under a capital lease are due as follows:

millions of dollars

Year of Maturity	
One year renewable	$ 168.0
2007	3.4
2008	121.4
2009	130.3
2010	105.3
2011	5.3
Greater than 5 years	1,127.1
	$ 1,660.8

22. COMMON SHARES

Authorized: Unlimited number of non-par value common shares.

Issued and outstanding:	Millions of Shares	Common Share Capital millions of dollars
January 1, 2005	108.87	$ 1,017.3
Issued for cash under purchase plans	0.43	7.9
Options exercised under senior management share option plan	0.80	13.0
Share-based compensation	–	1.0
December 31, 2005	110.10	1,039.2
Issued for cash under purchase plans	0.45	8.6
Options exercised under senior management share option plan	0.38	6.7
Share-based compensation	–	0.7
December 31, 2006	**110.93**	**$ 1,055.2**

As at December 31, 2006, there were 4.9 million (2005 – 0.3 million) common shares reserved for issuance under the senior management common share option plan, and 1.2 million (2005 – 1.3 million) common shares reserved for issuance under the employee common share purchase plan.

Dividend Reinvestment and Employee Common Share Purchase Plans

The Company has a Common Shareholder Dividend Reinvestment Plan, which provides an opportunity for shareholders to reinvest dividends and to make cash contributions for the purpose of purchasing common shares. The Company also has an Employee Common Share Purchase Plan to which the Company and employees make cash contributions for the purpose of purchasing common shares and which allows reinvestment of dividends.

Share-Based Compensation Plan

Common Share Option Plan

The Company has a common share option plan that grants options to senior management of the Company for a maximum term of ten years. The option price for these shares is the closing market price of the shares on the day before the option is granted.

All options granted to date are exercisable on a graduated basis with up to 25 percent of options exercisable on the first anniversary date and in further 25 percent increments on each of the second, third and fourth anniversaries of the grant. If an option is not exercised within ten years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The maximum number of such shares optioned to anyone cannot exceed one percent of the issued and outstanding common shares on the date the option is granted.

If, before the expiry of an option in accordance with its terms, the optionee ceases to be an eligible person due to retirement or a change of responsibility at the Company's request, such option may, subject to the terms thereof and any other terms of the plan, be exercised at any time within the 24 months following the date the optionee retires, but in any case prior to the expiry of the option in accordance with its terms.

If, before the expiry of an option in accordance with its terms, the optionee ceases to be an eligible person due to employment termination for just cause, resignation or death, such option may, subject to the terms thereof and any other terms of the plan, be exercised at any time within the six months following the date the optionee is terminated, resigns, or dies, as applicable, but in any case prior to the expiry of the option in accordance with its terms.

		2006		2005
	Shares under option	**Weighted average exercise price**	Shares under option	Weighted average exercise price
Outstanding, beginning of year	**1,696,475**	**$ 17.81**	1,939,750	$ 16.76
Granted	**578,700**	**$ 19.88**	569,500	$ 19.46
Exercised	**(382,750)**	**$ 19.20**	(797,775)	$ 16.43
Expired	**–**	**–**	(15,000)	$ 17.55
Outstanding, end of year	**1,892,425**	**$ 18.54**	1,696,475	$ 17.81
Exercisable, end of year	**743,225**	**$ 17.45**	702,750	$ 17.13

The weighted average contractual life of options outstanding at December 31, 2006 is 7.4 years (2005 – 7.6 years). The range of exercise prices for the options outstanding at December 31, 2006 is $13.70 to $19.88 (2005 – $13.70 to $19.50).

Deferred Share Unit Plan and Restricted Share Unit Plan

The Company has deferred share unit ("DSU") and restricted share unit ("RSU") plans.

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

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

When incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of a Company common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the then market value of an Emera common share.

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

RSUs are granted annually for three-year overlapping performance cycles. The first cycle ran from January 1, 2003 through December 31, 2005. RSUs are granted at fair value on the grant date and dividend equivalents are awarded and are used to purchase additional RSUs. The RSU value varies according to the Company's common share market price and corporate performance.

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

	Employee DSUs Outstanding	Employee RSUs Outstanding	Director DSUs Outstanding
Balance at January 1, 2005	140,130	305,250	32,022
Granted	33,463	132,280	14,381
Retirement, termination, disability & death	(43,307)	(76,281)	(6,967)
December 31, 2005	130,286	361,249	39,436
Granted	22,511	95,268	23,347
Retirement, termination, disability & death	(311)	(21,739)	–
Payout	–	(139,693)	–
December 31, 2006	**152,486**	**295,085**	**62,783**

The Company is using the fair value based method to measure the compensation expense related to its share-based compensation and employee purchase plan and recognizes the expense over the vesting period on a straight-line basis. The DSU and RSU liabilities are marked-to-market at the end of each period based on the common share price at the end of the period. For the year ended December 31, 2006, $7.1 million (2005 – $3.7 million) of compensation expense related to options granted, units issued and shares purchased by employees was recognized in operating, maintenance and general expense.

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for the grants:

	2006	2005
Expected dividend yield	**5.12%**	5.20%
Expected volatility	**14.04%**	14.12%
Risk-free interest rate	**4.27%**	4.32%
Expected life	**7 years**	7 years

23. CONTRIBUTED SURPLUS

The change in contributed surplus is due to the following:

millions of dollars	2006	2005
Balance, beginning of year	**$ 1.8**	$ 1.9
Stock option expense	**0.9**	0.7
Exercise of stock options	**(0.5)**	(0.8)
Balance, end of year	**$ 2.2**	$ 1.8

24. FINANCIAL INSTRUMENTS

The Company manages its exposure to foreign exchange, interest rate, and commodity risks in accordance with established risk management policies and procedures using derivative instruments consisting mainly of foreign exchange forward contracts, interest caps and collars, and oil and gas options and swaps.

Derivative financial instruments involve credit and market risks. Credit risks arise from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument.

Financial instruments include the following:

	2006		2005	
millions of dollars	**Carrying Amount Liability (Asset)**	**Fair Value Liability (Asset)**	Carrying Amount Liability (Asset)	Fair Value Liability (Asset)
Long-term debt	**$1,660.8**	**$1,925.5**	$ 1,784.7	$ 2,076.0
Short-term debt	**133.2**	**129.2**	88.1	88.1
Derivative financial instruments (hedges)				
Interest rate swaps	**–**	**–**	0.1	0.2
Interest rate caps and collars	**(0.1)**	**(0.1)**	(0.3)	(0.3)
Natural gas swaps	**–**	**(4.4)**	(4.0)	(13.4)
Oil swaps	**0.4**	**(11.0)**	(3.5)	(16.1)
Foreign exchange contracts	**(0.1)**	**(7.2)**	–	33.9
Derivative financial instruments (non-hedges)				
Energy marketing assets	**(39.3)**	**(39.3)**	(20.1)	(20.1)
Energy marketing liabilities	**38.1**	**38.1**	15.0	15.0

Long-Term Debt and Short-Term Debt

The fair value of Emera's long-term and short-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to Emera, for debt of the same remaining maturities.

Derivative Financial Instruments

The fair value of derivative financial instruments is estimated by obtaining prevailing market rates from investment dealers.

Interest Rates

The Company enters into interest rate hedging contracts to limit exposure to fluctuations in floating and fixed interest rates on its short-term and long-term debt.

Interest rate cap contracts limiting floating rate interest on $225.0 million short-term debt over 2007 to a fixed interest rate of 4.75% were outstanding at December 31, 2006. In addition, interest rate caps, at an average rate of 4.06%, on $239 million short-term debt over 2006 matured in January 2007.

Commodity Prices

The Company purchased natural gas swap contracts in 2006 to limit exposure to fluctuations in natural gas prices. As at December 31, 2006, the Company had hedged approximately 95% of all natural gas purchases associated with its forecasted natural gas burn for 2007, 35% for 2008, 30% for 2009, and 30% for 2010. In addition, the Company has hedged approximately 95% of natural gas sales associated with the Company's resale program for 2007, 70% for 2008, 65% for 2009, and 65% for 2010.

The Company enters into oil swap contracts to limit exposure to fluctuations in world prices of heavy fuel oil. As at December 31, 2006, the Company has hedged approximately 100% of 2007 requirements and 35% of 2008 requirements, and 5% of 2009 requirements.

On December 31, 2006 the Company held non-hedging natural gas, power and oil financial instruments which were marked-to-market.

Foreign Exchange

Emera enters into foreign exchange forward, option, and swap contracts to limit exposure to currency rate fluctuations. Currency forwards are used to fix the Canadian dollar cost to acquire US dollars, reducing exposure to currency rate fluctuations. Forward contracts to buy US $815.4 million over 2007 to 2010 at a weighted average rate of CAD $1.1374 were outstanding at December 31, 2006. Forward contracts to sell US $66.2 million in 2007 at a weighted average rate of CAD $1.1404 were outstanding at December 31, 2006.

On December 31, 2006, the Company held non-hedging foreign exchange financial instruments which were marked-to-market.

RISK MANAGEMENT

Commodity Price and Foreign Exchange Risk

A substantial amount of NSPI's fuel supply comes from international suppliers, and is subject to commodity price and foreign exchange risk. NSPI manages exposure to commodity price risk utilizing a combination of physical fixed-price fuel contracts and financial instruments providing fixed or maximum prices. Foreign exchange risk is managed through forward and option contracts. The risk inherent in the Canadian dollar cost of fuel is measured and managed on a portfolio basis.

The ability to switch fuel provides a dynamic, operational and effective option in managing commodity price and supply risk.

Interest Rate Risk

The Company makes use of various financial instruments to hedge against interest rate risk, as discussed above. Additionally, the Company uses diversification as a strategy. It maintains a portfolio of debt instruments which includes short-term instruments and long-term instruments with staggered maturities. The Company also deals with several counterparties so as to mitigate interest rate concentration risk.

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit assessments are conducted on all new customers and deposits are requested on any high risk accounts. The Company also maintains provisions for potential credit losses, which are assessed on a regular basis. With respect to customers other than electric customers, counterparty creditworthiness is assessed through reports of credit rating agencies or other available financial information.

25. FOREIGN EXCHANGE TRANSLATION ADJUSTMENT

The change in foreign exchange translation adjustment is due to the following:

millions of dollars	2006	2005
Balance, beginning of year	$ (98.2)	$ (82.0)
Effect of exchange rate changes	(2.0)	(16.2)
Balance, end of year	$ (100.2)	$ (98.2)

26. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera purchased natural gas transportation capacity totalling $29.3 million (2005 – $21.7 million) during the year ended December 31, 2006, 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, 2006 the amount payable to the related party is $3.4 million (2005 – $4.5 million), is non-interest bearing and is under normal credit terms

27. CONTINGENCIES

The Company has commenced arbitration against Aliant Inc., Bell Aliant Regional Communications LP and its related parties ("Aliant") claiming that, in 2003, Aliant unlawfully purported to terminate a certain telecommunications services agreement and related agreements pursuant to which Aliant, using certain assets sold by the Company to Aliant in 2000, provides telecommunications services to the Company at a certain price. Aliant has counterclaimed, claiming service fees it alleges are due in excess of the contract price provided in the telecommunications services agreement. The Company claims various remedies in respect of the telecommunications services agreement and related agreements. The outcome, and therefore an estimate of any contingent loss, of this litigation are not determinable.

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

Bangor Hydro-Electric has a potential liability to Great Lake Hydro America LLC for headwater benefits on the Penobscot River in connection with hydro assets sold to PPL Generation, LLC in 1999. The matter is currently before the Federal Energy Regulatory Commission for determination. The outcome, and therefore an estimate of any contingent loss, of this litigation are not determinable.

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

28. COMMITMENTS

In addition to commitments outlined elsewhere in these notes, Emera had the following significant commitments at December 31, 2006:

- The Company has an outsourcing commitment to a third party, beginning in early 2004 for seven years, at an annual cost ranging from $8.6 million to $10.4 million.
- NSPI has an annual requirement to purchase approximately 366 GWh of electricity from independent power producers over varying contract lengths ranging from seven to nineteen years.
- NSPI is required to purchase approximately 61,600 mmbtu of natural gas per day for the next four years (subject to offshore gas production), and an additional 4,000 mmbtu per day, at the option of the supplier, for five years.
- NSPI has a commitment to purchase approximately 61,000 mmbtu per day of transportation capacity on the Maritimes and Northeast Pipeline, a related party, for the next four years, and an additional 4,000 mmbtu per day, at the option of the supplier for five years. The commitment includes renewal rights at NSPI's option for an indefinite period of time, at an approximate cost of $16 million per year.
- NSPI is responsible for managing a portfolio of approximately $1.05 billion of defeasance securities held in trust. The defeasance securities must provide the principal and interest payment streams of the related defeased debt. Approximately 71%, or $742 million, of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio.
- NSPI has a commitment to a third party for the transportation of coal for ten years beginning in late 2002 at an approximate cost of $16 million per year.
- NSPI has a commitment to third parties for 2007 to 2010, to purchase 3.4 million cubic metric tons ("mts") of import coal, 936,000 mts of petroleum coke, 960,000 mts of domestic coal and 5.1 million mts of marine freight.
- NSPI has a commitment to a third party beginning in 2005 for 10 years to operate a facility at an annual cost of $4 million per year.
- Bangor Hydro has various contracts committing it to purchase annually approximately $12 million to $14 million of electricity for the period from 2007 to 2017 from independent power producers. These commitments are reduced to approximately $2 million from 2018 to 2023.

29. GUARANTEES

Emera had the following guarantees at December 31, 2006:

- The Company has letters of credit issued against its operating facility totalling $20.6 million. Emera's outstanding letter of credit is to secure payment to a vendor that expires in 2007 and is renewed annually. Nova Scotia Power's letters of credit extend to 2007 and/or are renewed annually and secure payments to various vendors and obligations under an unfunded pension plan. Bangor Hydro's letters of credit extend to 2007 and/or are renewed annually to secure payments to a vendor and for obligations under an unfunded pension plan.

30. COMPARATIVE INFORMATION

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted for 2006.

OPERATING STATISTICS
FIVE-YEAR SUMMARY

Year ended December 31	**2006**	2005	2004	2003	2002
Electric energy sales (GWh)					
Residential	**4,516.0**	4,602.7	4,632.4	4,391.1	4,401.6
Commercial	**3,621.1**	3,614.1	3,567.4	3,586.1	3,401.8
Industrial	**3,246.7**	4,600.3	4,556.1	4,449.8	4,225.9
Other	**1,550.8**	902.7	819.1	1,375.4	1,641.8
Total electric energy sales	**12,934.6**	13,719.8	13,575.0	13,802.4	13,671.1
Sources of energy (GWh)					
Thermal – coal	**9,128.1**	9,116.3	9,490.2	9,218.7	8,861.6
– oil	**431.9**	1,581.3	1,699.3	1,537.2	289.2
– natural gas	**390.3**	194.3	97.0	119.5	1,578.7
Hydro	**1,034.7**	1,092.6	983.5	1,176.8	1,108.7
Wind	**2.4**	1.8	2.4	2.6	0.3
Purchases	**3,144.7**	2,961.6	2,339.9	2,724.5	2,765.9
Total generation and purchases	**14,132.1**	14,947.9	14,612.3	14,779.3	14,604.4
Losses and internal use	**1,197.5**	1,228.1	1,037.3	976.9	933.3
Total electric energy sold	**12,934.6**	13,719.8	13,575.0	13,802.4	13,671.1
Electric customers					
Residential	**526,014**	520,671	515,726	509,824	501,233
Commercial	**50,780**	50,321	49,353	48,846	47,914
Industrial	**2,526**	2,515	2,455	2,393	2,325
Other	**9,378**	9,094	8,684	8,341	11,663
Total electric customers	**588,698**	582,601	576,218	569,404	563,135
Capacity					
Generating nameplate capacity (MW)					
Coal fired	**1,243**	1,243	1,243	1,243	1,243
Dual fired	**350**	350	350	350	350
Gas turbines	**323**	323	319	274	225
Hydro-electric	**1,005**	1,005	395	395	395
Wind turbines	**1**	1	1	1	1
Independent power producers	**120**	74	66	67	66
	3,042	2,996	2,374	2,330	2,280
Total number of employees	**2,149**	2,075	2,249	2,359	2,476
km of transmission lines	**5,900**	6,100	6,100	6,100	6,100
km of distribution lines	**33,000**	32,000	32,000	32,000	32,000

FIVE-YEAR SUMMARY

Year ended December 31 (millions of dollars)	2006	2005	2004	2003	2002
Statements of Earnings Information					
Revenue	**$ 1,166.0**	$ 1,168.0	$ 1,134.2	$ 1,146.8	$ 1,161.2
Cost of operations					
Fuel for generation and power purchased	**347.7**	432.0	350.0	363.3	453.2
Operating, maintenance and general	**255.6**	248.2	245.2	258.6	276.5
Provincial, state and municipal taxes	**48.0**	48.4	46.3	40.9	30.1
Provincial tax deferral	**–**	(4.5)	–	–	–
Depreciation	**145.2**	136.1	131.2	126.9	127.0
Regulatory amortization	**22.8**	19.4	26.1	18.2	23.9
Allowance for funds used during construction	**(5.8)**	(4.4)	(4.0)	(5.1)	(4.9)
	813.5	875.2	794.8	802.8	905.8
Earnings from operations	**352.5**	292.8	339.4	344.0	255.4
Equity earnings	**4.9**	6.5	6.2	8.6	7.0
Earnings before interest and income taxes	**357.4**	299.3	345.6	352.6	262.4
Interest	**127.1**	117.4	126.8	133.6	144.0
Amortization of defeasance costs	**12.7**	13.2	15.1	16.7	19.4
Other income	**(8.9)**	(8.0)	–	–	–
Earnings before income taxes	**226.5**	176.7	203.7	202.3	99.0
Income taxes	**87.4**	53.5	62.7	60.9	5.5
Income taxes deferral	**–**	(12.2)	–	–	–
Net earnings before non-controlling interest	**139.1**	135.4	141.0	141.4	93.5
Non-controlling interest	**13.3**	13.3	13.4	13.2	10.6
Net earnings from continuing operations	**125.8**	122.1	127.6	128.2	82.9
(Loss) earnings from discontinued operations	**–**	(0.9)	2.2	1.0	0.7
Net earnings applicable to common shares	**125.8**	121.2	129.8	129.2	83.6
Common dividends	**98.3**	97.4	95.5	92.8	84.4
Earnings retained for use in Company	**$ 27.5**	$ 23.8	$ 34.3	$ 36.4	$ (0.8)
Cost of fuel for generation – coal	**$ 266.2**	$ 260.9	$ 209.1	$ 211.9	$ 229.6
– oil	**34.3**	100.2	91.1	90.4	20.6
– natural gas	**(41.6)**	(35.4)	(30.6)	(58.4)	62.5
Power purchased	**88.8**	106.3	80.4	119.4	140.5
Total cost of fuel for generation and power purchased	**$ 347.7**	$ 432.0	$ 350.0	$ 363.3	$ 453.2
Balance Sheets Information					
Current assets	**$ 502.1**	$391.5	$332.1	$305.5	$331.7
Other assets	**574.5**	678.8	742.0	705.6	600.3
Investments	**101.3**	99.1	96.8	102.8	112.2
Property, plant and equipment	**2,881.9**	2,829.2	2,778.3	2,777.0	2,863.7
Total assets	**$ 4,059.8**	$3,998.6	$3,949.2	$3,890.9	$3,907.9
Current liabilities	**$ 501.8**	$506.4	$493.6	$520.2	$697.6
Other liabilities	**231.8**	233.4	231.5	207.8	193.0
Long-term debt	**1,657.4**	1,631.8	1,626.5	1,589.5	1,417.8
Non-controlling interest	**260.7**	260.8	260.8	260.8	267.5
Common shares	**1,055.2**	1,039.2	1,017.3	1,007.2	999.8
Contributed surplus	**2.2**	1.8	1.9	1.2	0.4
Foreign currency translation adjustment	**(100.2)**	(98.2)	(82.0)	(61.1)	2.9
Retained earnings	**450.9**	423.4	399.6	365.3	328.9
Total equity and liabilities	**$ 4,059.8**	$ 3,998.6	$ 3,949.2	$ 3,890.9	$ 3,907.9
Statements of Cash Flow Information					
Cash provided by operating activities	**$ 345.8**	$ 164.3	$ 304.6	$ 251.9	$ 272.4
Cash used in investing activities	**$ 203.0**	$ 117.2	$ 214.5	$ 85.2	$ 109.6
Cash used in financing activities	**$ 156.7**	$ 68.3	$ 57.4	$ 184.4	$ 157.3
Financial Ratios ($ per common share)					
Earnings per common share	**$ 1.14**	$ 1.11	$ 1.20	$ 1.20	$ 0.85

BOARD OF DIRECTORS

Derek Oland
Chairman, Emera Inc.
Executive Chairman
Moosehead Breweries
Limited
New River Beach,
New Brunswick

Christopher G. Huskilson
President and
Chief Executive Officer
Emera Inc.
Enfield, Nova Scotia

Robert S. Briggs
Company Director
Former President and
Chief Executive Officer
Bangor Hydro-Electric Company
Carrabassett Valley, Maine

Dr. Gail Cook-Bennett
Chair, Canada Pension Plan
Investment Board
Toronto, Ontario

Allan L. Edgeworth
President
ALE Energy Inc.
Calgary, Alberta

John T. McLennan
Chairman, Nova Scotia Power Inc.
Company Director,
Former Vice Chair and
Chief Executive Officer
Allstream Inc.
Mahone Bay, Nova Scotia

Dr. Elizabeth Parr-Johnston
President
Parr Johnston Economic
and Policy Consultants
Chester Basin, Nova Scotia

Andrea S. Rosen
Company Director,
Former Vice Chair
TD Bank Financial Group
and President,
TD CanadaTrust
Toronto, Ontario

Paul D. Sobey
President and
Chief Executive Officer
Empire Company Limited
Kingshead, Pictou County,
Nova Scotia

COMMITTEES

Emera Inc. Audit Committee
Paul D. Sobey (Committee Chair)
Robert S. Briggs
Gail Cook-Bennett
Andrea S. Rosen (effective May 2007)

Emera Inc. Management Resources and Compensation Committee:
Elizabeth Parr-Johnston
(Committee Chair)
Allan L. Edgeworth
John T. McLennan

Emera Inc. Nominating and Corporate Governance Committee:
Gail Cook-Bennett
(Committee Chair)
John T. McLennan
Elizabeth Parr-Johnston

Dividend Payments in 2006

Subject to Approval by the Board of Directors, common share dividends for Emera Inc. are payable on or about the 15th for February, May, August and November. A first quarter dividend of $0.2225 has been declared payable February 15, 2007.

A quarterly dividend of $0.30625 is payable on the 1st of January, April, July and October for Nova Scotia Power Inc.'s Series C First Preferred Shares.

A quarterly dividend of $0.36875 is payable on the 15th of January, April, July and October for Nova Scotia Power Inc.'s Series D First Preferred Shares.

Dividend Reinvestment and Share Purchase Plan

Emera's Dividend Reinvestment and Share Purchase Plan is available to shareholders resident in Canada. The plan provides shareholders with a convenient and economical means of acquiring additional common shares through the reinvestment of dividends. Plan participants may also contribute cash payments of up to $5,000 per quarter. Participants of the plan pay no commissions, service charges, or brokerage fees for shares purchased under the Plan.

Please contact Investor Services if you have questions or wish to receive a copy of the plan brochure and enrollment form.

Direct Deposit Service

Shareholders may have dividends deposited directly into accounts held at financial institutions that are members of the Canadian Payments Association. To arrange this service, please contact Investor Services.

Quarterly Earnings

Quarterly earnings are expected to be announced May 1, July 27 and November 2, 2007. Year-end results for 2006 will be released in February 2007.

Annual General Meeting

The Annual General Meeting is scheduled to be held May 1, 2007 at 2:00 p.m. (Atlantic Time) at the World Trade and Convention Centre in Halifax, Nova Scotia.

CORPORATE INFORMATION

For general inquiries about our company please contact our corporate office:

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Information regarding company news and initiatives including our 2006 Financial Report is also available at our web site, www.emera.com

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Director, Investor and External Relations
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Share Listings
Toronto Stock Exchange (TSX)
Common Shares: EMA
Preferred Shares:
NSI.PR.C, NSI.PR.D

Shares Outstanding
Common Shares:
110,926,173
(as of December 31, 2006)

Dividends Paid in 2006
$0.89 per Common Share

Emera