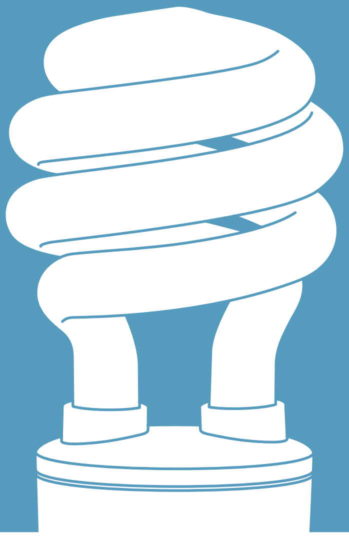
2004 annual financial report



Emera

To My Fellow Shareholders

I am honoured to have the opportunity to write to shareholders for the first time as President and Chief Executive Officer.

When I began my career with our Company, as a young engineer 25 years ago, I did not have my sights set on the CEO's chair. **I was excited about my new job, ready for the challenges, and determined to make a difference.** I rolled up my sleeves and worked hard. Every area of the business interested me. Years passed, and many things changed – in the world, in the industry, and in the company. One thing has not – I am as enthusiastic today about this Company and the opportunity it presents as I was on the day that I walked in the door.

In last year's annual report we talked a lot about "positive energy", and that phrase continues to resonate with me. Emera is in a period of transition, with a new leader and a new team. Our goal is simple…to turn that *positive energy* into *progress*, then *momentum*, then greater *success*.

Emera earned $129.8 million in 2004. That provides solid support to our dividend, which was increased in early 2005 to $.89 annually. We understand the critical importance of our dividend to our investors. They rely on it for income, and expect it to grow over time. From Emera's perspective, dividend growth can only flow from earnings growth. For the past several years, earnings per share growth has eluded us. We are determined to change that.

In 2004, and into 2005, much effort has been focused on increasing the predictability of our earnings, which we believe is a critical step in delivering on our investment value proposition.

To that end, Nova Scotia Power (NSPI), our largest subsidiary, applied to its regulator for new rates for 2005, essentially to include corporate income taxes in its cost structure. NSPI has been fully taxable since 2003, but the company managed to cover that annual multi-million dollar expense with the proceeds from opportunistic natural gas sales and aggressive fuel cost management. That was fine in the short-term, but a regulated utility should not have to depend on an unpredictable commodity market in order to have a reasonable opportunity to earn its allowed return. The full complement of costs must be included in the rate structure. NSPI also requested a fuel adjustment mechanism, a new idea in Nova Scotia, but one that is common elsewhere. More time may be required to fully resolve this issue, but if so, we believe we will be able to advance the process with additional stakeholder consultation. We await the regulator's decision.

Bangor Hydro-Electric (BHE) is also recalibrating its rate structure. BHE and its key stakeholders agreed on a settlement which was approved by the Maine regulator that will set stranded cost rates for the next three years. And finally, our third regulated asset, the Maritimes & Northeast Pipeline, is seeking to reset tolls on the US pipeline to allow recovery of the Phase III investment which extended the line to Beverly, Massachusetts.

All of these initiatives will serve to better match regulated rates with costs. There will be a reset on earnings as a result of these rate cases. The reset will reflect a slightly lower allowed return on equity consistent with the current interest rate environment. We believe the increased predictability gives us a solid base on which to build.

First predictability, then steady, modest growth. Late in 2004, Emera, in partnership with Brascan Power Inc., announced that it would acquire three hydro-electric generating plants in New England. These high quality assets are low cost supply sources in the region that fit our skill set and risk profile, and will increase our annual generation by more than 500 GWh. They will add earnings, expand Emera's portfolio of renewable generation, and increase our opportunities in the growing northeast US marketplace. We are working to close these transactions by mid-year, and diligently looking for more just like them.

Another opportunity currently in play is the *Northeast Reliability Interconnect (NRI)*, a new electric transmission line connecting New Brunswick and Maine. Bangor Hydro-Electric is working to secure regulatory and environmental approvals to construct and operate the line, after having received a tariff commitment from the Independent System Operator in New England. The NRI is expected to be fully operational by 2007, and will improve system efficiency, reliability and power quality. This new Maritimes/New England connection will expand the northeast market and enhance cross-border power flow opportunities in both directions.

There were other accomplishments in 2004. NSPI's Point Tupper facility was named the top performing thermal power facility for 2003 by The Canadian Electricity Association. Point Tupper outperformed 87 other thermal generating units across the country for the Number 1 ranking, operating at 99% of capacity for the previous year. Two other NSPI facilities ranked in the Top 10. This best-in-class performance demonstrates the operational skills that our company is leveraging.

Another first was NSPI's "Customer Energy Forum" where we brought 135 randomly selected Nova Scotians together to start important discussions about Nova Scotia's energy future. Participants had an opportunity to listen to, and ask questions of, a variety of stakeholders in addition to NSPI, including government, environmental groups, alternative energy suppliers and large industrial customers. Big questions about new electricity supply, generation options and emissions issues are coming to the forefront. It is essential that we reach out and engage customers and stakeholders in them.

Using an approach called Deliberative Polling®, developed at Stanford University and never before used in Canada, the forum set out to collect informed opinion rather than "off the top of the head" opinion. Our objective is to find out where customers see the balance on the environment, energy prices and the economy. Nova Scotians take these issues seriously, and participants arrived well prepared to discuss them. Our commitment is to listen to what they say and factor it into our planning.

There is always a lot of talk about weather in Nova Scotia, and rarely more so than in the past 15 months, beginning with Hurricane Juan in September 2003. In November of 2004, a severe and unusual winter storm with accumulations of

"I am excited about my new job, ready for the challenges, and determined to make a difference."

heavy, wet snow and ice caused a loss of service for a significant portion of our customers. The storm actually made Environment Canada's list of the country's top 10 weather events last year, and left our customers feeling more vulnerable and concerned about the effects of weather events.

The UARB will be holding a hearing in the spring to review NSPI's performance through this event. We welcome the opportunity to hear from our customers about their expectations, and also to highlight the high standards under which we operate, and the improvements to reliability that have been achieved.

Bangor Hydro has been a successful investment for Emera. In the past three years we have lowered the rates in Maine, improved the service quality and consistently met service quality indicators and created value for shareholders.

Our newest business, Emera Energy Services, has grown steadily. This business provides services to gas and electricity customers across the region, adding profitable revenue to Emera.

Although NSPI has been producing electricity for decades, it has really only been "in business" since privatization in 1992. Emera has only existed since 2000. We operate in a complex industry, and as an investor-owned, monopoly-provider of an essential service to Mainers and Nova Scotians, we are constantly in the public eye and on the financial line. We are building the foundation that will support future success.

I strongly believe Emera is positioned to meet the needs and changing expectations of customers – by finding innovative ways to provide more cost effective service, and by understanding that it's not enough to simply run great assets. Successful businesses must also demonstrate they care about their customers, and are working hard to deliver the kind of service that customers want. My pledge to both our shareholders and customers is for our companies to continue to measure and achieve success against this demanding and changing standard.

We are grateful to our employees for their skill and dedication. I am proud to lead this team. I thank David Mann for his leadership to Emera and to me over the past eight years. I also thank Derek Oland, Chairman of the Board, and the Directors for the confidence they have placed in me, and for their ongoing support and guidance.

I echo my sentiments from 1980, I am excited about my new job, ready for the challenges and determined to make a difference.

Respectfully yours,

Christopher G. Huskilson
President and Chief Executive Officer

Fellow Shareholders

This past year, your Board of Directors was focused on arguably its most important responsibility – providing effective leadership through the selection of a new President and Chief Executive Officer at Emera Inc.

After nearly a decade of successful leadership, David Mann retired in November. I would like to pay tribute on behalf of the Board to David for his valuable and effective guidance completing our transformation from a Crown Corporation into one of the region's largest players in the energy sector.

The Board was extremely fortunate to have David's successor rise from within the ranks of the Company. Chris Huskilson joined Nova Scotia Power as a junior engineer twenty-five years ago, and has been involved in just about every operational aspect of the business. He has demonstrated his leadership and surefootedness time and time again, and was the Board's unanimous choice to lead Emera into the future.

The transition could not have been smoother. I thank the Board for its diligence and hard work through this period, and on the Directors' behalf I congratulate both Chris and David on their efforts.

We are saying goodbye to some valued Directors. Purdy Crawford and Rosemary Scanlon made major contributions to the Board during their time with us and will be missed. I would particularly like to thank Purdy for his effective leadership as the Chair of the Management Resources and Compensation Committee, which orchestrated the executive leadership transition.

Emera's success in attracting quality leadership continues as we welcome two new Directors to Emera's Board. Gail Cook-Bennett has been a Corporate Director for many years and is currently Chair of the Canada Pension Plan Investment Board. John McLennan recently retired as Vice-Chair and CEO of Allstream Inc. and has held many senior positions in the telecommunications industry. We look forward to working with Gail and John on your behalf.

The expectations of Boards of Directors with respect to their oversight responsibilities are increasing, and Emera is taking steps to ensure that our governance processes continue to meet the highest standards. For example, in 2004, we expanded our financial disclosures to improve transparency and accountability. We also conducted a thorough review of Board Committee mandates to ensure they are current with best practices, enabling Committees to exercise proper oversight on behalf of shareholders.

Emera earned just under $130 million in 2004, a modest increase over 2003. That performance was achieved in the face of significantly higher taxes, and a volatile energy market. On behalf of the Board, I thank Management and our employees for their hard work in challenging circumstances.

The Board continues to provide expert guidance to management as it retools strategy in a dynamic economic, industry and market environment. In 2004, the Company advanced its growth strategy with the acquisition of three hydro-electric generating facilities in New England at Bellows Falls, Bear Swamp, and Fife Brook. These acquisitions, and ultimately others like them, will benefit from Emera's operating experience and contribute to our bottom line.

Emera is entering the second half of the decade with continued confidence. I am certain our three most important stakeholder groups – customers, investors and employees – will continue to be well served with solid leadership that balances their interests and our obligations to each of them.

Yours truly,

Derek Oland
Chairman of the Board of Directors

as at February 11, 2005

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 2004 relative to 2003, and the full year 2004 relative to 2003, and its financial position at December 31, 2004. Certain factors that may impact 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. 2004 audited consolidated financial statements and supporting notes. Emera follows Canadian Generally Accepted Accounting Principles ("GAAP"). Emera's subsidiary, Nova Scotia Power Inc.'s ("Nova Scotia Power" or "NSPI") accounting policies are subject to examination and approval by the Nova Scotia Utility and Review Board ("UARB") and are similar to those being used by other companies in the electric utility industry in Canada. Emera's subsidiary, Bangor Hydro-Electric Company's ("Bangor Hydro" or "BHE") accounting policies are subject to examination and approval by the Federal Energy Regulatory Commission ("FERC") and the Maine Public Utility Commission ("MPUC") and are similar to those being used by other companies in the electric utility industry in Maine. The rate-regulated accounting policies of NSPI 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, unless otherwise noted.

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

CONSOLIDATED FINANCIAL HIGHLIGHTS

millions of dollars (except earnings per common share)	Three months ended December 31		Year ended December 31		
	2004	2003	**2004**	2003	2002
Revenues	**$ 309.4**	$ 310.3	**$ 1,222.0**	$ 1,231.3	$ 1,227.2
Net earnings	**31.4**	47.5	**129.8**	129.2	83.6
Earnings per common share	**0.30**	0.44	**1.20**	1.20	0.85
Net cash provided by operating activities	**62.3**	103.6	**304.0**	251.9	272.4

Introduction and Strategic Overview

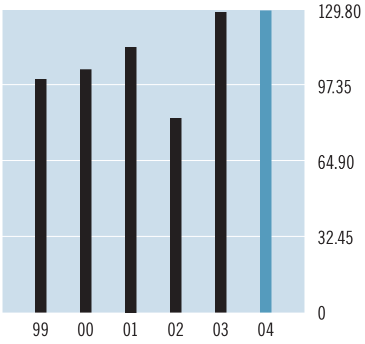
The core business of Emera is electricity. The Company operates two regulated electric utilities in northeast North America, which together comprise 90% of consolidated revenues:

- **Nova Scotia Power Inc. ("NSPI")** is a wholly-owned, **fully integrated**, **regulated electric utility**, with $3 billion of assets, serving 460,000 customers. NSPI is the primary electricity supplier in Nova Scotia, providing the vast majority of the generation, transmission and distribution of electricity in the province.
- **Bangor Hydro-Electric Company ("BHE")** is a wholly-owned **regulated electricity transmission and distribution company** with $600 million of assets serving 110,000 customers in eastern Maine.

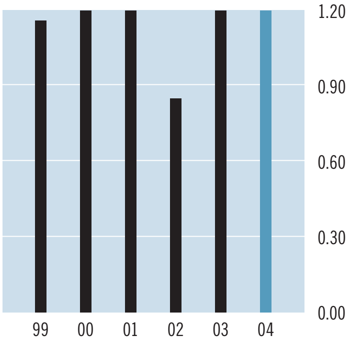
The success of Emera's electric utilities is integral to delivering on shareholder value, providing substantial earnings and cash flow that support dividends and reinvestment. Emera's utilities enjoy essentially monopoly status within regulated environments, which can generally be expected to result in relatively stable earnings streams. Sustaining that privileged position depends on continuing to satisfy customers with the right combination of price and service quality. Accordingly, cost management, including generating capacity management/asset utilization, reliability, quality customer service and management of regulatory relationships are key success factors for Emera's electricity business.

Emera strives for continuous improvement in its financial and operating results. In 2004, the Company's earnings per common share were $1.20, unchanged from 2003.

Consolidated Net Earnings History
(millions of dollars)



Earnings Per Share History
(dollars)



As previously noted, Emera's electricity businesses are regulated, which limits upside earnings potential, all other things being equal. In addition, Nova Scotia and Maine are mature electricity markets, with annual demand growth in the range of 2%. Accordingly, Emera must look beyond its existing regulated electricity business for incremental earnings growth.

Emera's disciplined plan for growth seeks to add energy infrastructure assets to its portfolio. The Company is focused on building on its core electricity business, specifically in regulated transmission and distribution operations, and low risk generation facilities. Emera is currently concentrating its efforts in northeast North America, which is continuing to develop as an integrated energy market.

Opportunities arising from the development of Nova Scotia's offshore natural gas reserves continue to be of interest to Emera over the longer term, to the extent that they relate to gas supply for the Company's electricity generation assets.

Success for Emera's growth strategy depends on:

- identifying and executing opportunities for profitable growth;
- building strong partnerships with industry leaders; and
- capitalizing on synergies among businesses in Emera's expanding energy infrastructure portfolio.

Pending Transactions

In December 2004, consistent with its strategy for growth, Emera invested in two hydro generation facilities as follows:

Bellows Falls Power Company ("BFP"), a 50-50 joint venture between Brascan Power Inc. and Emera Inc., entered into an agreement to lease the 49 megawatt Bellows Falls hydro-electric generating facility, located on the Connecticut River in Vermont, from the Town of Rockingham, following the Town's acquisition of the facility. BFP will pay US $72 million to lease the facility for up to 74 years (Emera's share – US $36 million). Bellows Falls is expected to generate approximately 230 GWh hours annually. The transaction is pending regulatory approvals and is expected to close in the second quarter of 2005. Emera has placed its full share of the purchase price in escrow, pending completion of the transaction. The amount is included in deferred assets on the consolidated balance sheet.

Brascan Power Inc. and Emera Inc., in a 50-50 joint venture, will acquire Bear Swamp, a 589 megawatt pumped storage hydro-electric generating facility in northern Massachusetts, for a total of US $92 million (Emera's share – US $46 million). Bear Swamp is located on the Deerfield River in northern Massachusetts. 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 facility. The transaction is conditional on approvals of regulatory agencies and is expected to close in mid-2005. Each party has paid a deposit of US $4.5 million, pending completion of the transaction. The amount is included in deferred assets on the consolidated balance sheet.

In accordance with its accounting policy for new business costs, Emera has capitalized total new business development costs of $0.9 million, which are directly related to these two acquisitions. These costs will become part of the allocated purchase prices.

Upon closing, Emera's costs to acquire these projects will total approximately US $84 million. On an annual basis, the projects are estimated to generate earnings before depreciation, interest, and income taxes of approximately US $10 million to US $14 million.

Structure of MD&A

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, Emera Fuels and corporate activities are grouped and discussed as "Other". Liquidity and capital resources, significant changes in consolidated balance sheets, outstanding share data, financial and commodity instruments, transaction with related parties, critical accounting estimates, dividend policy and payout ratios, discussion of business risks and enterprise risk management and summary of quarterly reports 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 2004	2003	Year ended December 31 2004	2003	2002
Electric revenue	**$ 276.9**	$ 280.0	**$ 1,095.7**	$ 1,104.1	$ 1,136.3
Fuel oil	**24.9**	20.5	**87.8**	84.5	66.0
Other	**9.6**	9.8	**38.5**	42.7	24.9
	311.4	310.3	**1,222.0**	1,231.3	1,227.2
Fuel for generation and purchased power	**97.0**	83.1	**350.0**	363.3	453.2
Cost of fuel oil sold	**21.2**	16.8	**75.0**	71.5	57.3
OM&G	**65.2**	66.7	**254.6**	269.4	284.2
Provincial and state grants and taxes	**11.4**	10.1	**46.3**	40.9	30.1
Depreciation	**32.6**	27.5	**132.0**	127.7	127.8
Regulatory amortization	**6.8**	4.3	**26.1**	18.2	23.9
Other	**(2.8)**	(2.8)	**(10.2)**	(13.7)	(11.9)
Earnings before interest and income taxes	**80.0**	104.6	**348.2**	354.0	262.6
Interest	**30.5**	32.6	**126.8**	133.6	144.0
Amortization of defeasance costs	**3.8**	4.1	**15.1**	16.7	19.4
Earnings before income taxes	**45.7**	67.9	**206.3**	203.7	99.2
Income taxes	**10.9**	17.1	**63.1**	61.3	5.0
Net earnings before non-controlling interest	**34.8**	50.8	**143.2**	142.4	94.2
Non-controlling interest	**3.4**	3.3	**13.4**	13.2	10.6
Net earnings applicable to common shares	**$ 31.4**	$ 47.5	**$ 129.8**	$ 129.2	$ 83.6
Earnings per common share – basic	**$ 0.30**	$ 0.44	**$ 1.20**	$ 1.20	$ 0.85
Earnings per common share – diluted	**$ 0.28**	$ 0.43	**$ 1.16**	$ 1.15	$ 0.84
Cash dividends declared per share	**$ 0.220**	$ 0.215	**$ 0.88**	$ 0.86	$ 0.86

OPERATING UNIT CONTRIBUTIONS

millions of dollars (except earnings per common share)	Three months ended December 31 2004	2003	Year ended December 31 2004	2003	2002
Nova Scotia Power	**$ 25.0**	$ 41.7	**$ 107.3**	$ 112.1	$ 86.1
Bangor Hydro-Electric	**4.4**	4.4	**18.5**	18.8	18.8
Other	**2.0**	1.4	**4.0**	(1.7)	(21.3)
Consolidated net earnings	**$ 31.4**	$ 47.5	**$ 129.8**	$ 129.2	$ 83.6
Earnings per common share – basic	**$ 0.30**	$ 0.44	**$ 1.20**	$ 1.20	$ 0.85
Earnings per common share – diluted	**$ 0.28**	$ 0.43	**$ 1.16**	$ 1.15	$ 0.84

Review of Q4, 2004

Emera Inc.'s consolidated earnings were $31.4 million in Q4, 2004, compared to $47.5 million in Q4 2003.
The quarter over quarter change primarily reflects:

- A $17.0 million ($10.5 million after-tax) decrease in electric sales margin primarily because of higher unit production costs in Nova Scotia Power. This is the result of reduced gas resale margins resulting from changes to the pricing structure in the supply contract; and higher commodity prices, including costs to source replacement fuel associated with a supplier's default on contracted deliveries.
- A $5.1 million increase in depreciation expense both before and after tax. This is primarily due to a $3.8 million reduction in depreciation expense in NSPI in Q4, 2003 because actual site restoration costs for the Glace Bay generating station were lower than estimated. In addition, the Company's electric utilities recently conducted depreciation studies, and implemented higher depreciation rates as a result.

Review of 2004

For the year ended December 31, 2004, Emera's consolidated net earnings were $129.8 million, compared to $129.2 million in 2003 and $83.6 million in 2002. Highlights of the earnings changes are summarized in the following table:

millions of dollars	
Consolidated net earnings, December 31, 2002	**$ 83.6**
Increased electric revenues reflecting NSPI's 3% rate increase in late 2002	36.5
Lower fuel costs, including an additional $41.3 million of net gas sales proceeds	44.4
Increased provincial grants and taxes in NSPI	(11.4)
Increased energy marketing margin	9.8
Increased income taxes as NSPI becomes fully taxable	(42.1)
Lower tax recoveries due to improved financial results	(12.3)
Reduced business development expenses	9.6
Decreased interest expense reflecting lower rates and reduced debt levels	10.4
Write-off of CBDC contract termination fee in 2002	13.4
Write-downs in 2002	11.9
Adjustment to NSPI's and BHE's unbilled revenue in 2003	(13.2)
Hurricane Juan operating expenses in 2003	(6.0)
All other	(5.4)
Consolidated net earnings, December 31, 2003	**$ 129.2**
Increased electric revenues in NSPI, reflecting load growth	21.3
Higher fuel expenses in NSPI, due to reduced gas sales margin and higher coal costs in Q4	(25.3)
Increased provincial grants and taxes in NSPI	(6.1)
Increase in energy marketing margin	12.5
Increased depreciation in NSPI, reflecting updated rates, and capital investment	(14.3)
Decreased interest expense reflecting lower debt levels and interest rates	6.8
Adjustment to NSPI's and BHE's unbilled revenue in 2003	13.2
Hurricane Juan operating expenses in 2003	6.0
Cessation of SOEP processing fees and depreciation expense on sale of asset	(5.7)
All other	(7.8)
Consolidated net earnings, December 31, 2004	**$ 129.8**

Earnings per share were unchanged year over year at $1.20.

SIGNIFICANT ITEMS

2004

There were no significant items in 2004.

2003

Unbilled revenue adjustment

The Company recognizes electric revenues on the accrual basis, which includes an estimate of electricity consumed by customers in the period but billed subsequently ("unbilled revenue"). In 2003, the Company improved its process for estimating its unbilled revenue. The change resulted in one-time reductions in unbilled revenue accruals, with corresponding charges against revenues as follows:

- NSPI $10.0 million ($6.5 million after-tax) in Q2, 2003
- BHE $3.2 million ($1.9 million after-tax) in Q3, 2003

Hurricane Juan

In Q3, 2003 Nova Scotia was struck by Hurricane Juan, a Category Two hurricane causing extensive damage to Nova Scotia Power's transmission and distribution system. The total cost of the hurricane to the Company was $12.6 million, specifically $4.0 million of net after-tax operating costs that were recorded in Q3, 2003, and $8.6 million in capital costs.

Site restoration costs

Prior to 2003, Nova Scotia Power estimated and accrued site restoration costs for the Glace Bay generating station. The costs to complete the restoration were expected to be $3.8 million lower than estimated. Nova Scotia Power reduced its provision accordingly, with a corresponding reduction in depreciation expense in Q4, 2003.

2002

Contract termination fee

In October 2002, as part of its decision on Nova Scotia Power's 2002 Rate Application, the Nova Scotia Utility and Review Board disallowed recovery from ratepayers of a $13.4 million contract termination fee paid to the Cape Breton Development Corporation ("CBDC") in 2001 to terminate its coal supply contract, which otherwise extended to 2010. As a result, NSPI expensed this fee in Q4, 2002.

Coal bed methane project

Also during Q4, 2002 the Company reviewed its investment in a coal bed methane project, and determined that the project was not economically viable in the forseeable future. Accordingly, the $5.5 million investment was expensed.

Nova Scotia Power Inc.

OVERVIEW

NSPI is the primary electricity supplier in Nova Scotia, providing over 95% of the electricity generation, transmission and distribution in the province. The company owns 2,293 megawatts (MW) of generating capacity. Approximately 54% is coal-fired; oil and natural gas fired facilities together comprise another 28% of capacity; and hydro and wind production provide the remainder. In 2003, NSPI contracted with an independent power producer for approximately 100 gigawatt hours per year of wind power annually. NSPI also owns approximately 5,000 kilometres of transmission facilities, and 25,000 kilometres of distribution facilities. The company has a workforce of approximately 1,600 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.

Currently, NSPI's allowed return on common equity ("ROE") range is 9.9% to 10.4%. In 2004, NSPI earned within its allowed range. Equity is deemed to be 35% of total capitalization for rate-making purposes, but the company is permitted to maintain common equity up to 40%.

In 2004, NSPI filed for new rates, effective for 2005, primarily to incorporate substantially higher corporate taxes into its rate structure. The company requested an additional $101.9 million in annual revenue, which translates to an average rate increase of 12.4% for customers. NSPI requested a range of return of 10.2%–11.2% on a common equity component of 37.5%. Hearings were conducted in November. In December, NSPI, with the support of several key stakeholders, filed a negotiated proposed Settlement Agreement with the UARB in connection with the rate application. NSPI agreed to several concessions in the course of settlement negotiations, including reducing its ROE request to a range of 9.3% to 10.3%, and recovery of its pre-2003 income tax deposit over 17 years instead of the seven years proposed in the original rate application. As a result, the proposed Settlement Agreement reduces the average rate increase for customers to 7.3%. Hearings into the proposed Settlement Agreement were held in early January. The UARB is under no obligation to accept the Settlement Agreement. A decision on the Rate Application/Settlement Agreement is pending.

In the meantime, beginning on January 1, 2005, the UARB has agreed to allow NSPI to defer new taxes not presently in rates until rates allowed by the UARB in the 2005 Rate Application become effective. The amount of the deferral will be determined after year-end, and the period over which the deferral will be amortized will be determined at that time.

REVIEW OF 2004

NSPI NET EARNINGS

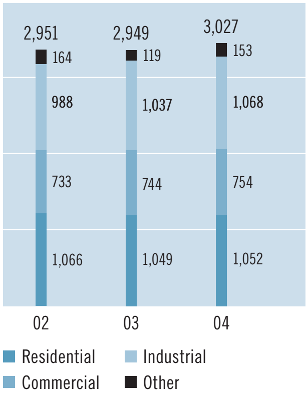
	Three months ended December 31		Year ended December 31		
millions of dollars (except earnings per common share)	**2004**	2003	**2004**	2003	2002
Electric revenue	**$ 237.8**	$ 231.2	**$ 926.9**	$ 895.6	$ 869.1
Fuel for generation and purchased power	**86.9**	63.5	**303.1**	277.8	335.6
Operating, maintenance and general	**46.4**	45.1	**177.5**	186.0	176.4
Provincial grants and taxes	**9.9**	8.3	**39.5**	33.4	22.0
Depreciation	**28.2**	23.2	**116.0**	101.7	103.9
Regulatory amortization	**1.5**	1.5	**6.2**	6.2	1.0
Other	**(2.5)**	(4.4)	**(10.4)**	(13.5)	(10.8)
Earnings before the following	**67.4**	94.0	**295.0**	304.0	241.0
Interest	**24.6**	26.6	**100.1**	104.3	109.6
Amortization of defeasance costs	**3.8**	4.1	**15.1**	16.7	19.4
Earnings before income taxes	**39.0**	63.3	**179.8**	183.0	112.0
Income taxes	**10.7**	18.3	**59.2**	57.8	15.7
Earnings before preferred dividends	**28.3**	45.0	**120.6**	125.2	96.3
Preferred dividends	**3.3**	3.3	**13.3**	13.1	10.2
Contribution to consolidated net earnings	**$ 25.0**	$ 41.7	**$ 107.3**	$ 112.1	$ 86.1
Contribution to consolidated earnings per common share	**$ 0.23**	$ 0.39	**$ 0.99**	$ 1.04	$ 0.87

NSPI's net earnings were $25.0 million in Q4, 2004 compared to $41.7 million in Q4, 2003. The quarter over quarter change primarily reflects a $16.8 million decrease in the electric margin as a result of higher fuel costs.

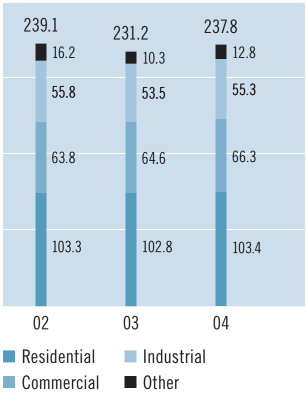
For the year ended December 31, 2004, NSPI's net earnings were $107.3 million, compared to $112.1 million in 2003 and $86.1 million in 2002. Highlights of the earnings changes are summarized in the following table:

millions of dollars	
Contribution to consolidated net earnings, December 31, 2002	**$ 86.1**
Increased electric revenues, reflecting 3% rate increase late in 2002	36.5
Decreased fuel costs, including an additional $41.3 million of net gas sales proceeds	44.4
Increased provincial grants and taxes	(11.4)
Increased amortization of Glace Bay generating station	(5.2)
Increased income taxes as NSPI becomes fully taxable	(42.1)
Decreased interest, reflecting $75 million equity infusion and debt refinancing	5.3
Write-off of CBDC contract termination fee in 2002	13.4
Adjustment to the company's unbilled revenue in 2003	(10.0)
Hurricane Juan operating expenses in 2003	(6.0)
All other	1.1
Contribution to consolidated net earnings, December 31, 2003	**$ 112.1**
Increased electric revenues, largely reflecting load growth	21.3
Increased fuel expenses, due to reduced gas sales margin and higher coal costs in Q4	(25.3)
Increased depreciation, reflecting updated rates, and capital investment	(14.3)
Increased provincial grants and taxes	(6.1)
Adjustment to the company's unbilled revenue in 2003	10.0
Hurricane Juan operating expenses in 2003	6.0
All other	3.6
Contribution to consolidated net earnings, December 31, 2004	**$ 107.3**

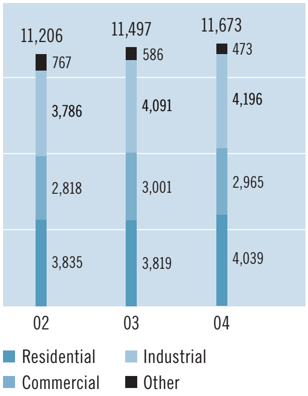
Q4 Electric Sales Volume
(GWh)



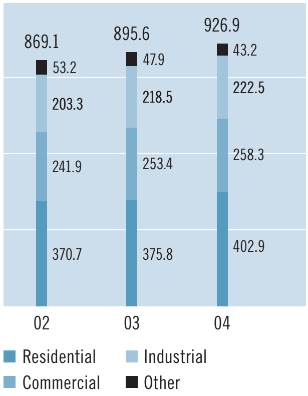
Q4 Electric Sales Revenues
(millions of dollars)



YTD Electric Sales Volume
(GWh)



YTD Electric Sales Revenues
(millions of dollars)



Q4 AVERAGE REVENUE / MWH

	2004	2003	2002
Dollars per MWh	$ 79	$ 78	$ 81

YTD AVERAGE REVENUE / MWH

	2004	2003	2002
Dollars per MWh	$ 79	$ 78	$ 78

Electric sales *volume* is primarily driven by general economic conditions, population and weather. Electricity *pricing* in Nova Scotia is regulated, and therefore stays stable for extended periods of time, only changing as new regulatory decisions are implemented. The exceptions are Annually Adjusted Rates, subscribed to by larger industrial customers, which apply to approximately 20% of NSPI sales volume; and export sales, which typically comprise approximately 5% of NSPI sales volume, and are priced at market. Of late, export sales have been lower as available capacity is used to service in-province load. Residential and commercial electricity sales are seasonal in Nova Scotia, 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 $6.6 million to $237.8 million in Q4, 2004 from $231.2 million for the same period in 2003. Sales volume increases are substantially due to the expansion of a large industrial customer, and higher exports.

For the year ended December 31, 2004, electric revenues increased $31.3 million to $926.9 million from $895.6 million in 2003. Of the difference, $10.0 million relates to a charge against revenue in the 2003 comparative amounts, due to an adjustment to the company's unbilled revenue accrual. In addition to normal growth, a cold Q1, 2004 increased sales volumes. Export sales volumes were lower, as available capacity was used to service in-province load.

For the year ended December 31, 2003, electric revenues increased $26.5 million to $895.6 million from $869.1 million in 2002. The revenue increase is primarily due to the 3% rate increase, implemented in November 2002. The positive impact of the price increase was partially offset by the adjustment to unbilled revenue, which led to a reallocation of revenue from residential to other customer classes.

Outlook

In 2005, volume growth is expected to increase electric revenues by approximately 2%. The overall revenue outlook is substantially dependent on the outcome of the company's rate application. The magnitude of any approved increase, as well as the timing of implementation, will affect revenues, and could have a material impact on earnings. The company is awaiting the decision of its regulator in this matter.

FUEL FOR GENERATION AND PURCHASED POWER

Capacity

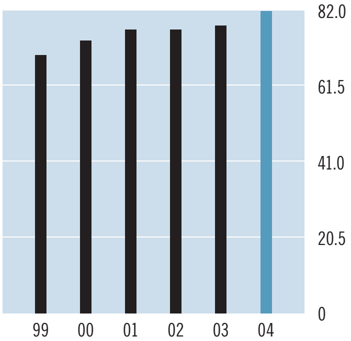
To ensure reliability of service, NSPI maintains a generating capacity greater than firm peak demand. In 2004, a second LM6000 gas turbine, with a nameplate capacity of 50 MW, was installed at the Tufts Cove Plant. That brought the total company-owned generation capacity to 2,293 MW, which is supplemented by 25 megawatts contracted with independent power producers. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area in order to meet the North-East Power Coordinating Council criteria.

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 impact on earnings, and helps defer significant investment in additional generation capacity. Maximizing capacity utilization primarily depends on three factors:

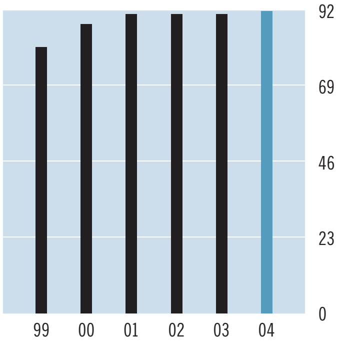
- *Moving demand from peak to non-peak periods* – NSPI encourages customers to move some electricity demand from high cost to lower cost periods by offering customers various pricing alternatives. Energy taken under NSPI's residential Time of Use rate has increased by 7% from 2003, effectively shifting electric space heat load for these customers. NSPI offers the 2-Part Real-Time Pricing and the Extra Large Industrial Interruptible Rate ("ELIIR") to encourage industrial customers to maintain high load factors and shift load based on pricing signals. Over 300 MW of interruptible electric load exists.
- *Increasing export sales* – Increasing export sales when margins are satisfactory allows excess capacity to be sold when not required in province. In 2004, NSPI established a 24-hour energy marketing desk to optimize commercial opportunities for NSPI.
- *Ensuring generating plants are consistently available to service demand* – NSPI conducts ongoing planned maintenance programs, and has managed to sustain NSPI's high availability over the past several years. In addition, an indicator of the effectiveness of NSPI's plant maintenance is the company's unplanned outage rate, which was 2.7% in 2004 (2003 – 2.5%).

NSPI's generating capacity utilization has grown 17% since 1999, from 69.8% to 81.5% in 2004. That utilization is made possible by availability performance, which reached 92% in 2004.

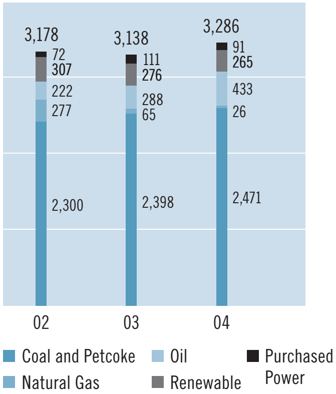
NSPI Thermal Capacity Utilization
(percent)



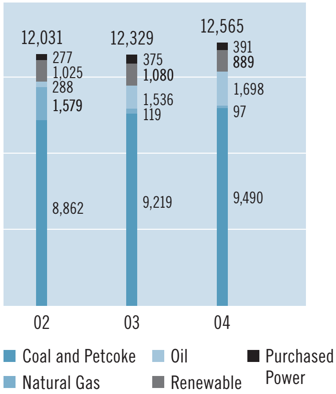
NSPI Generating Capacity Availability
(percent)



Q4 Production Volume
(GWh)



YTD Production Volume
(GWh)



Q4 AVERAGE UNIT FUEL COSTS

	2004	2003	2002
Dollars per MWh	$ 26	$ 20	$ 31

YTD AVERAGE UNIT FUEL COSTS

	2004	2003	2002
Dollars per MWh	$ 24	$ 23	$ 28

Coal is NSPI's dominant fuel source, supplying approximately 55% of the company's annual generation. Petroleum coke ("petcoke") fuels approximately 21% 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. 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.

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 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. Further details on the company's fuel cost risk management strategies are included in the Business Risks and Enterprise Risk Management section.

Fuel for generation and purchased power expense increased $23.4 million, or 37%, to $86.9 million in Q4, 2004 compared to $63.5 million in the fourth quarter of 2003. Unit production costs increased 30%, from $20 per MWh in Q4, 2003 to $26 per MWh in Q4, 2004. This is substantially due to reduced gas resale margins resulting from changes to the pricing structure in the supply contract; and higher commodity prices, including costs to source replacement fuel associated with a supplier's default on contracted deliveries.

For the year ended December 31, 2004 fuel for generation and purchased power was $303.1 million, compared to $277.8 million in 2003, and $335.6 million in 2002. Highlights of the year over year changes are summarized in the following table:

millions of dollars	
Fuel for generation and purchased power, December 31, 2002	**$ 335.6**
Higher net proceeds from resale of natural gas	(41.3)
Increased production	18.0
Lower commodity pricing	(20.6)
Write-off of CBDC contract termination fee in 2002	(13.4)
All other	(0.5)
Fuel for generation and purchased power, December 31, 2003	**$ 277.8**
Lower net proceeds from resale of natural gas	32.0
Decreased export volumes	(11.4)
Decreased renewable production volumes	11.9
Increased production	16.9
Commodity pricing, including favourable exchange rates	(16.7)
All other	(7.4)
Fuel for generation and purchased power, December 31, 2004	**$ 303.1**

Outlook

NSPI's fuel expense in 2005 is expected to be approximately $393 million. The increase is primarily due to three factors:

- higher prices for import coal and oil;
- an increase in the amount of higher cost, lower-sulphur coal in the fuel mix to meet environmental requirements; and
- reduced net proceeds from the resale of natural gas due to the renegotiation of the supply contract.

Substantially all of these increased costs are addressed in NSPI's proposed rate Settlement Agreement for 2005. A decision on the Rate Application/Settlement Agreement is pending.

OPERATING, MAINTENANCE AND GENERAL EXPENSES

NSPI's operating, maintenance and general expenditures ("OM&G") were $46.4 million in Q4, 2004 compared to $45.1 million in Q4, 2003 primarily as a result of higher storm related expenses. An increase in pension expense was substantially offset by cost control in other areas.

For the year ended December 31, 2004, NSPI's OM&G expenditures were $177.5 million, compared to $186.0 million for 2003 and $176.4 million in 2002. OM&G expenditures decreased $8.5 million in 2004 from 2003 levels primarily as a result of a continued focus on controlling costs including labour and materials. The increase in OM&G costs in 2003 over 2002 is driven by increased pension costs and costs incurred during the repair and restoration work resulting from Hurricane Juan.

Outlook

2005 OM&G expenditures are expected to be approximately $180 million.

PROVINCIAL GRANTS AND TAXES

NSPI pays annual grants to the Province of Nova Scotia, in lieu of all municipal taxation other than deed transfer tax. Provincial grants and taxes increased $1.6 million in Q4, 2004, to $9.9 million, compared to $8.3 million in Q4, 2003. The increase reflects the quarterly impact of the $4.6 million increase in NSPI's annual provincial grants levied in the spring of 2003, which took effect in Q1, 2004; and the increase in the provincial capital tax rate from 0.25% to 0.3%, effective April 1, 2004.

For the year ended December 31, 2004, provincial grants and taxes increased $6.1 million to $39.5 million compared to $33.4 million in 2003, reflecting the tax increases referred to above. The 2003 amount was $11.4 million higher than 2002, reflecting an additional tax increase of $11.0 million which took effect in Q1, 2003.

Outlook

Provincial grants and taxes are expected to increase slightly in 2005, reflecting the increase in the provincial capital tax rate and inflationary adjustments.

DEPRECIATION

NSPI's depreciation expense increased $5.0 million in Q4, 2004 to $28.2 million, compared to $23.2 million in Q4, 2003. The quarter over quarter difference is primarily due to a $3.8 million reduction in depreciation expense in Q4, 2003 because actual site restoration costs for the Glace Bay generating station were lower than estimated.

For the year ended December 31, 2004, depreciation increased $14.3 million to $116.0 million, compared to $101.7 million in 2003. The increase reflects the change in depreciation rates approved by the UARB in its 2003 depreciation order, the reduction in depreciation expense in Q4, 2003 noted above, and normal increases due to planned capital spending. The 2003 amount was $2.2 million lower than 2002, reflecting the $3.8 million reduction in depreciation expense in Q4, 2003.

Outlook

During 2003, following completion of a depreciation study, and a negotiated agreement with stakeholders, NSPI's regulator approved a $20 million increase in annual depreciation expense, to be phased in over four years beginning in 2004. Revised depreciation rates were incorporated in NSPI's rate application for 2005. As part of the proposed Settlement Agreement, NSPI has requested a one-year delay in the phase-in of the new depreciation rates, which would amount to approximately $5 million in depreciation expense. Under the Settlement Agreement, depreciation expense is expected to approximate $122 million in 2005.

REGULATORY AMORTIZATION

The Glace Bay generating station has been permanently shut down and is being written off through 2008 if required, at an annual minimum rate of $6.2 million. The amount remaining to be written off is $17.8 million. Regulatory amortization is included in NSPI's revenue requirement.

INTEREST

NSPI's interest expense decreased $2.0 million, to $24.6 million in Q4, 2004 compared to $26.6 million in Q4, 2003 due to the refinancing of a $140 million mid-term note with short-term debt in 2004.

For the year ended December 31, 2004, interest expense decreased $4.2 million, to $100.1 million compared to $104.3 million in 2003. This decrease is due to the refinancing noted above. The 2003 amount was $5.3 million lower than 2002, reflecting lower rates on debt refinanced and reduced debt levels as a result of a $75 million common equity issue to Emera in December 2002.

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

Outlook

In 2005, interest expense is expected to approximate 2004 levels.

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 (0.288%), large corporations tax (0.2%), corporate income tax (38.12%) and Part VI.1 tax relating to preferred dividends (40%).

In 2003, NSPI became fully taxable. Prior to that, NSPI used sufficient capital cost allowance, cumulative eligible capital deductions and loss carry-forwards to eliminate corporate income tax. As a result, through 2002, income tax costs consisted only of Part VI.1 tax on NSPI preferred dividends.

NSPI had filed income tax returns for previous years to claim deductions related to the capitalization of interest on assets constructed by its predecessor, Nova Scotia Power Corporation ("NSPC"). The Canada Customs and Revenue Agency (now the Canada Revenue Agency ("CRA")) disallowed the deductions claimed, and NSPI pursued the issue through to the Supreme Court of Canada ("the Supreme Court"). In June 2004 the Supreme Court dismissed Nova Scotia Power's appeal to allow income tax deductions the company had claimed between 1998 and 2002. The deductions represented approximately $129 million in income tax otherwise payable ($150 million including interest).

NSPI deposited the amount owing with CRA in 2001 and 2003 in order to avoid incurring non-deductible interest charges in the event its Supreme Court appeal was unsuccessful. The UARB provided an accounting order allowing NSPI to defer the amount while the matter was before the Supreme Court and recognized that depending on the outcome, NSPI could apply to the UARB to amortize the deferred amounts.

In its Rate Application for 2005, NSPI requested rates that would enable amortization of the tax deposit over a seven-year period starting in 2005. In a component of the Settlement Agreement filed in December, NSPI proposes the amortization period be extended to 17 years instead of the seven years proposed in the original rate application, to reduce the impact on rates. The UARB's decision is pending, and until such time, the deposit continues to be deferred.

In the meantime, beginning on January 1, 2005, the UARB has agreed to allow NSPI to defer new taxes not presently in rates until rates allowed by the UARB in the 2005 Rate Application become effective. The amount of the deferral will be determined after year end, and the period over which the deferral will be amortized will be determined at that time.

DEBT MANAGEMENT

In 2004, a $140.0 million 7.3% mid-term note matured and was refinanced with short-term debt.

In 2003, a $150.0 million 7.7% debenture matured; and $300.0 million of medium-term notes were issued, with the proceeds used to refinance the maturing debenture, and pay down short-term debt.

The weighted-average coupon rate on NSPI's outstanding medium-term and debenture notes at December 31, 2004, was 7.32% (2003 – 7.32%). Approximately 37% of the debt matures over the next ten years; 59% matures between 2015 and 2036; and $50.0 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 5.14% as of December 31, 2004 (2003 – 5.39%).

NSPI has established the following available credit facilities:

millions of dollars	Maturity	Maximum amount
Short-term		
Commercial paper, with 100% backup line of credit	1 Year Revolving	$ 350.0
Operating credit facility	1 Year Revolving	$ 100.0

NSPI has the following available credit ratings:

	DBRS		S&P		Moodys	
	2004	2003	**2004**	2003	**2004**	2003
Long-term corporate	**A (low)**	A (low)	**BBB+**	BBB+	**na**	na
Senior unsecured debt	**A (low)**	A (low)	**BBB+**	BBB+	**Baa1**	Baa1
Preferred stock	**Pfd-2 (low)**	Pfd-2 (low)	**P-2 (Low)**	P-2 (Low)	**na**	na
Commercial paper	**R-1 (low)**	R-1 (low)	**A-1 (Low)**	A-1 (Low)	**P-2 (Baa)**	P-2 (Baa)

Based on the Company's available credit and credit ratings, and past experience in public financing since privatization, NSPI expects to have access to capital when needed.

Outlook

In May 2005, $100.0 million of NSPI's long-term debt will mature. The maturing debt bears interest at 8.38%. Based on NSPI's credit rating and current market conditions, NSPI expects to refinance this maturity in 2005 at favourable rates. Pending a decision on its Rate Application/Settlement Agreement, NSPI's capital structure is expected to remain essentially unchanged in 2005.

REGULATORY DEVELOPMENTS

Beginning in 2003, NSPI implemented a stakeholder consultation process in an effort to improve the efficiency and effectiveness of its regulatory process. This new practice includes technical conferences with stakeholders, during which information is exchanged, issues are identified and discussed, and where possible, proposals for resolution can be developed for consideration by the UARB. In 2003, NSPI successfully used this process to resolve issues related to the adoption of the Extra Large Industrial Interruptible Rate, Generic Rate Design, depreciation, Annually Adjusted Rates, and the development of a two-part Real-Time Pricing (RTP) rate. In 2004, NSPI continued this approach in its Open Access Transmission Tariff filing, new generation capacity process and its rate application. Customers and other stakeholders including the UARB have publicly complimented NSPI on this more consultative approach.

Outlook

Key elements of NSPI's regulatory plans for 2005 include:

- hearing for the Open Access Transmission Tariff filing;
- hearing regarding the November 2004 storm. The company is not able to forecast the outcome of this hearing at this time; and
- working with the UARB on its review to improve the regulatory process and make it more efficient and effective.

Bangor Hydro-Electric Company

OVERVIEW

In October 2001, Emera acquired Bangor Hydro-Electric Company ("BHE") for cash consideration of $316.6 million. Bangor Hydro is the second largest electric utility in Maine and greatly enhances Emera's presence in the Northeast energy market.

Since the restructuring of the electricity sector in Maine in 2000, BHE's core business has been the transmission and distribution of electricity ("T&D"). BHE owns and operates approximately 900 kilometres of transmission facilities, and 7,000 kilometres of distribution facilities. BHE has a workforce of approximately 300 people.

In addition to its T&D assets, 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 regulator. BHE's net regulatory assets primarily include the unamortized portion of its loss on the sale of its investment in the Seabrook nuclear facility; and the costs associated with the buy-out/restructure of above-market power purchase contracts. Unlike T&D operational assets, which must be 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 $119 million at December 31, 2004, or 19% of BHE's net asset base.

Approximately 50% of BHE's electric rate represents distribution service, 40% relates to stranded cost recoveries, and 10% 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"); the distribution operations and stranded cost recoveries are regulated by the Maine Public Utilities Commission ("MPUC").

In June 2002, the MPUC approved BHE's Alternate Rate Plan, or 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 sharing mechanism between the company and customers outside of the earnings band. The ARP also includes average annual reductions in distribution rates of approximately 2.5% for five years, beginning in 2003.

In March 2002, the MPUC approved a three-year stranded cost recovery Rate Application, providing an allowed return of 11% on BHE's stranded asset base. BHE is required to hold stranded cost proceedings at least every three years to adjust any substantial differences in the stranded cost estimates from prior periods that may arise because of differences between forecast and actual sales volumes or the output of facilities subject to purchased power agreements. On September 30, 2004 Bangor Hydro filed direct testimony with the MPUC regarding the Stranded Cost Revenue Requirement for the three-year period March 1, 2005 to February 28, 2008. The company and other parties involved have reached a settlement agreement on issues presented in the rate proceeding, and a stipulation was entered into and filed with the MPUC commissioners for their consideration. The stipulation contains an approximately 37% reduction in the average annual stranded cost revenue requirement for the 2005–2008 term. This would be largely offset by the completion of amortization of a major regulatory asset and increased revenue from the resale of purchased power due to higher market prices, and accordingly, net earnings will only decrease marginally. It is expected that the MPUC commissioners will issue a final rate order approving the stipulation prior to March 1, 2005.

Transmission rates are set annually, based on the prior year's revenue requirement. The current allowed ROE for transmission operations is 11.25%.

REVIEW OF 2004

BHE NET EARNINGS

millions of dollars (except earnings per common share)	Three months ended December 31 2004	Three months ended December 31 2003	Year ended December 31 2004	Year ended December 31 2003	Year ended December 31 2002
Electric revenue	$ 36.2	$ 38.8	$ 151.1	$ 159.3	$ 179.4
Resale of purchased power	2.4	8.0	14.1	36.6	62.1
Standard offer service	–	–	–	–	19.5
	38.6	46.8	165.2	195.9	261.0
Fuel for generation and purchased power	10.2	18.2	45.4	76.4	115.1
Operating, maintenance and general	10.6	11.6	41.2	46.3	55.7
Property taxes	1.4	1.6	6.4	6.8	7.6
Depreciation	3.7	2.8	14.0	13.5	16.5
Regulatory amortization	5.3	2.7	19.9	12.0	22.9
Other	(1.1)	(0.3)	(4.2)	(4.9)	(4.4)
Earnings before interest and income taxes	8.5	10.2	42.5	45.8	47.6
Interest	3.0	3.4	13.5	14.4	17.8
Earnings before income taxes	5.5	6.8	29.0	31.4	29.8
Income taxes	1.0	2.4	10.4	12.5	10.6
Earnings before preferred dividends	4.5	4.4	18.6	18.9	19.2
Preferred dividends	0.1	–	0.1	0.1	0.4
Contribution to consolidated net earnings	$ 4.4	$ 4.4	$ 18.5	$ 18.8	$ 18.8
Contribution to consolidated earnings per common share	$ 0.04	$ 0.04	$ 0.17	$ 0.17	$ 0.19
Weighted average foreign exchange rate	1.2216	1.3147	1.2957	1.4158	1.5455

Bangor Hydro's contribution to consolidated net earnings was $4.4 million in Q4, 2004 and Q4, 2003.

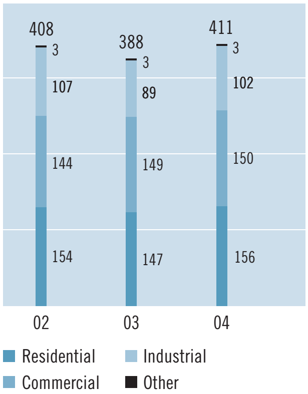
For the year ended December 31, 2004, Bangor Hydro's contribution to consolidated net earnings was $18.5 million compared to $18.8 million in both 2003 and 2002. Highlights of the earnings changes are summarized in the following table:

millions of dollars	
Contribution to consolidated net earnings, December 31, 2002	**$ 18.8**
Reduction in labour costs due to restructuring in 2002	3.0
Impact of stronger Canadian dollar	(1.8)
Adjustment to the company's unbilled revenue in 2003	(3.2)
All other	2.0
Contribution to consolidated net earnings, December 31, 2003	**$ 18.8**
Decrease in labour costs	4.0
Impact of stronger Canadian dollar	(1.8)
Adjustment to the company's unbilled revenue in 2003	3.2
All other	(5.7)
Contribution to consolidated net earnings, December 31, 2004	**$ 18.5**

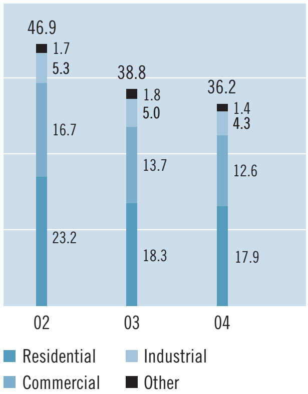
U.S. dollar earnings for 2004 were up $1.1 million to $14.4 million from $13.3 million in 2003, reflecting lower operating, maintenance and general expenses. Increased regulatory amortization was mitigated by increased electric margin.

REVENUE

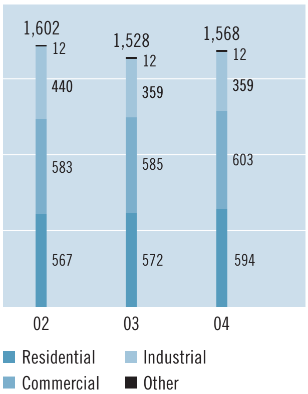
Q4 T&D Sales Volume
(GWh)



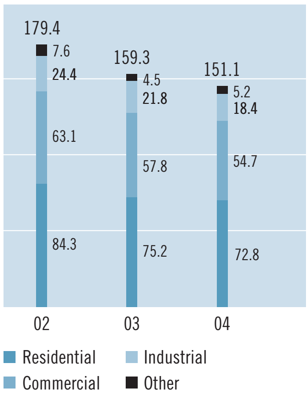
Q4 T&D Sales Revenues
(millions of dollars)



YTD T&D Sales Volume
(GWh)



YTD T&D Sales Revenues
(millions of dollars)



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. Residential and commercial electricity sales are sea-sonal in Maine, with Q1 and Q4 the strongest periods, reflecting colder weather, and fewer daylight hours at those times of year.

BHE's electric revenues decreased by $2.6 million in Q4, 2004, to $36.2 million compared to $38.8 million in Q4, 2003. Revenues declined $2.9 million related to the stronger Canadian dollar, partially offset by increased residential sales in 2004 compared to 2003, due to colder weather.

For the year ended December 31, 2004, electric revenues decreased $8.2 million, to $151.1 million from $159.3 million in 2003. While electric sales volume increased in 2004 due to growth, reported revenues were reduced $12.2 million as a result of the stronger Canadian dollar. The unbilled revenue adjustment in Q3, 2003 also impacted the year over year change. Average revenue per MWh decreased from $104 in 2003 to $96 in 2004 as a result of the stronger Canadian dollar.

BHE's distribution electric rates decreased by 2.5% on July 1, 2003, pursuant to its Alternative Rate Plan. At the same time, transmission electric rates increased by approximately 18%, with the net impact of these two rate changes resulting in a small increase in electric operating revenues. In November 2003, the company's transmission electric rates were increased by an additional 5.8%.

Bangor Hydro's electric sales revenues decreased $20.1 million in 2003, to $159.3 million from $179.4 million in 2002 primarily due to the impact of the stronger Canadian dollar. The rate changes mentioned above contributed to a small increase in electric operating revenues. Average revenue per MWh decreased from $111 in 2002 to $104 in 2003. Rate changes mentioned above were offset by the impact of the stronger Canadian dollar.

Outlook

As previously noted, Bangor Hydro has filed a stipulation with the MPUC in connection with its Stranded Cost Revenue Requirement for the three-year period March 1, 2005 to February 28, 2008. The stipulation contains an approximately 37%, or $20 million excluding the impact of the relative changes in the Canadian and US dollars, reduction in the average annual stranded cost revenue requirement, which would be largely offset by the completion of the amortization of a major regulatory asset and increased revenue from the resale of purchased power due to higher market prices for electricity. It is expected that the MPUC commissioners will issue a final rate order approving the stipulation prior to March 1, 2005.

STANDARD OFFER SERVICE

BHE ceased to provide standard offer service as of March 1, 2002.

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

The company has several above-market purchase power contracts pre-dating the Maine market restructuring. It also had a large above-market contract that ended in February 2004. Power purchased under these arrangements is resold to a third party at market rates. The cessation of the contract in February 2004 was the primary reason for the decrease in both resale of purchased power and purchased power and fuel for generation, quarter over quarter and year over year. The stronger Canadian dollar contributed $0.8 million to the reduction quarter over quarter and $3.6 million year over year.

Approximately $9.0 million of the decrease from 2002 to 2003 is due to the impact of the stronger Canadian dollar. For all of these contracts, the excess of costs over revenues over the term of the contracts has been estimated and factored into the company's stranded cost recovery rates.

Outlook

Excluding the impact of changes in the relative value of the Canadian and US dollars, revenues from the resale of purchased power are expected to be approximately $2 million higher in 2005 due to higher market prices for electricity net of reduced revenues associated with the expiration of a large purchased power contract in Q1, 2004. Purchased power expense in 2005 is expected to be $2 million lower than 2004 due to the expiration of this purchased power contract, offset somewhat by higher transmission costs. The increased sales from resale and the impact of the expired purchased power contract are included in the stranded cost revenue reduction discussed above.

OPERATING, MAINTENANCE AND GENERAL EXPENSES

Operating expenses were $1.0 million lower in Q4, 2004 at $10.6 million compared to $11.6 million in Q4, 2003, primarily due to the $0.8 million impact of a stronger Canadian dollar.

For the year ended December 31, 2004, BHE's operating expenses were $41.2 million compared to $46.3 million in 2003 and $55.7 million in 2002 as summarized below:

millions of dollars		
Operating, maintenance and general expenses, December 31, 2002	**$**	**55.7**
Reduced payroll costs reflecting the 2002 restructuring		(3.0)
Impact of stronger Canadian dollar		(6.4)
All other		–
Operating, maintenance and general expenses, December 31, 2003	**$**	**46.3**
Reduced labour		(4.0)
Impact of stronger Canadian dollar		(3.0)
All other		1.9
Operating, maintenance and general expenses, December 31, 2004	**$**	**41.2**

Outlook

Excluding the impact of changes in the relative value of the Canadian and U.S. dollars, 2005 OM&G is expected to decrease by $5 million, principally as a result of savings realized from implementing automated metering, and other cost-cutting measures.

DEPRECIATION

Depreciation expense increased by $0.9 million in Q4, 2004 compared to Q4, 2003, and increased $0.5 million in 2004 relative to 2003, due principally to the impact of the effect of plant additions in 2003 and 2004. The results of BHE's depreciation study, completed in 2004, are also included in the results.

Depreciation expense decreased by $3.0 million in 2003 relative to 2002 due principally to the impact of certain electric plant retirements in 2002, and the end of the depreciable lives of certain computer and other shorter-lived assets in 2003. These reductions were offset to some extent by the effect of plant additions in 2003.

Outlook

Depreciation expense is expected to increase slightly in 2005 as a result of continued electric plant investment and the implementation of the depreciation study.

REGULATORY AMORTIZATION

Regulatory amortization Q4, 2004 was $5.3 million, up from $2.7 million in Q4, 2003. The annual 2004 regulatory amortization was $19.9 million, up from $12.0 million in 2003. The increase reflects completion of the amortization period for several regulatory liabilities in Q1, 2004. The increase was somewhat offset by reduced 2004 amortization associated with BHE's stranded cost levelizer. In addition, regulatory amortization was reduced by approximately $0.4 million in the quarter and $1.5 million in the year due to the impact of the weaker U.S. currency.

In 2003, regulatory amortization was $12.0 million, down from $22.9 million in 2002. The decrease reflects the fact that during the year, in accordance with regulatory requirements, the company amortized a substantial portion of the deferred gain that arose on the sale of its generation assets in the course of industry restructuring. In addition, approximately $1.5 million of the decrease is due to the impact of the stronger Canadian dollar.

Outlook

Excluding the impact of changes in the relative value of the Canadian and US dollars, amortization is expected to decrease by approximately $7 million in 2005 and increase approximately $4 million in 2006. The changes are principally the result of expiring regulatory amortizations net of the effect of new amortizations created by new stranded cost rates being implemented on March 1, 2005. While changes in the amortization expense can be significant from year to year, the stranded cost revenues are adjusted to factor in the annual regulatory amortization, such that the impact on net earnings is minimal.

INTEREST

BHE's interest expense decreased to $3.0 million in Q4, 2004 from $3.4 million in Q4, 2003, and $13.5 million in 2004 from $14.4 million in 2003 and $17.8 million in 2002, due to the impact of the stronger Canadian dollar, and lower rates on debt refinanced.

Bangor Hydro manages exposure to interest rate risk 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).

DEBT MANAGEMENT

The weighted-average coupon rate on Bangor Hydro's long-term debt outstanding at December 31, 2004, was 7.13% (2003 – 7.09%). Approximately 66% of the debt matures over the next 15 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 4.94% as of December 31, 2004 (2003 – 4.63%).

Bangor Hydro has established the following credit facilities:

millions of dollars	Maximum amount
Short-term	
Unsecured revolving facility	$72.2 (US $60)
Operating line of credit	$12.0 (US $10)

During 2003, Bangor Hydro refinanced all of its public debt privately, 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.

REGULATORY MATTERS

When it acquired Bangor Hydro in 2001, Emera became a registered public utility holding company under the Public Utility Holding Company Act ("PUHCA"). PUHCA is administered by the U.S. Securities and Exchange Commission ("SEC"). In the normal course of regulating registered public utility holding companies, the SEC reviews each registered holding company's compliance with PUHCA approximately once every three to five years. In this regard, an SEC review of Emera began in the fall of 2004 and SEC staff have completed their field visit. The Company is awaiting the SEC's report on the results of the review and no significant issues have been identified to date.

Other

All activities of Emera outside of its two regulated electric utilities are incorporated in Other, including:

- A 12.9% interest in the $2.1 billion, 1,000 kilometre **Maritimes & Northeast Pipeline** (M&NP) that transports Nova Scotia's offshore natural gas to markets in Maritime Canada and the northeastern United States. M&NP is regulated by the National Energy Board in Canada, and the Federal Energy Regulatory Commission in the U.S., and has an overall allowed rate of return on equity of approximately 13.5%. The investment is accounted for on the equity basis. Emera's equity investment as at December 31, 2004 was $88.0 million (2003 – $91.4 million).
- **Emera Energy Services**, which manages energy assets on behalf of third parties and provides related value optimization services. Energy Services conducts its commercial transactions with minimal commodity risk exposure.
- **Emera Fuels**, an unregulated subsidiary that distributes home heating oil, heavy fuel oil, lubricants and related products to over 22,000 customers in the Maritime Provinces.
- Certain corporate-wide functions such as strategic planning, treasury services, tax planning and corporate governance; and financing for the corporation's business outside of its electric utilities.

In 2003 Emera sold its 8.4% interest in the Sable Offshore Energy Project's ("SOEP") offshore platforms and sub-sea gathering lines to Pengrowth Corporation, at book value effective July 1, 2003.

REVIEW OF 2004

OTHER NET EARNINGS (LOSS)

	Three months ended December 31		Year ended December 31		
millions of dollars (except earnings per common share)	2004	2003	2004	2003	2002
Fuel oil sales	$ 24.9	$ 20.9	$ 88.3	$ 91.4	$ 66.0
M&NP equity earnings	1.2	2.1	6.2	9.6	9.1
SOEP processing fees	–	1.4	–	16.3	11.2
Energy marketing margin	6.7	3.9	24.2	11.7	1.9
Coal transportation margin	–	–	–	–	2.3
	32.8	28.3	118.7	129.0	90.5
Cost of fuel oil sold	21.1	17.1	75.3	77.5	57.3
Operating maintenance and general	7.6	9.0	30.1	29.9	36.4
Business development	0.5	1.3	5.7	8.2	17.8
Depreciation	0.6	1.5	1.9	12.5	7.4
Other	(1.1)	(1.0)	(5.0)	(3.3)	(2.4)
Earnings (loss) before interest and income taxes	4.1	0.4	10.7	4.2	(26.0)
Interest	2.9	2.6	13.2	14.9	16.6
Earnings (loss) before income taxes	1.2	(2.2)	(2.5)	(10.7)	(42.6)
Income tax recovery	(0.8)	(3.6)	(6.5)	(9.0)	(21.3)
Contribution to consolidated net earnings	$ 2.0	$ 1.4	$ 4.0	$ (1.7)	$ (21.3)
Contribution to consolidated earnings per common share	$ 0.02	$ 0.01	$ 0.04	$ (0.01)	$ (0.21)

The contribution of Other operations to consolidated net earnings increased $0.6 million in Q4, 2004 compared to the same period in 2003. Higher energy marketing margin offset decreases in SOEP fees and equity earnings from the Maritimes & Northeast Pipeline.

For the year ended December 31, 2004, Other operations contributed $4.0 million to consolidated net earnings, compared to losses in 2003 and 2002 of $1.7 million and $21.3 million respectively. Highlights of the year over year changes are summarized in the following table:

millions of dollars	
Contribution to consolidated net earnings, December 31, 2002	**$ (21.3)**
Reduced business development activity	9.6
Increase in energy marketing margin	9.8
Reduced income tax recovery	(12.3)
Write-downs in 2002	11.9
All other	0.6
Contribution to consolidated net earnings, December 31, 2003	**$ (1.7)**
Cessation of SOEP processing fees on sale of asset	(16.3)
Increase in energy marketing margin	12.5
Cessation of SOEP depreciation expense on sale of asset	10.6
All other	(1.1)
Contribution to consolidated net earnings, December 31, 2004	**$ 4.0**

GROSS MARGIN ON FUEL OIL SALES

Emera Fuels' revenues and cost of sales can vary substantially from period to period as a result of commodity price changes, which impact both the revenue and cost of sales lines in approximately equal measure. Accordingly, gross margin, which reflects the net of revenue and cost of sales, is the most meaningful measure of financial performance. Emera Fuels' gross margin in the fourth quarter of both 2004 and 2003 was $3.8 million. For the year ended December 31, 2004, Emera Fuels' gross margin was $13.0 million, compared to $13.9 million in 2003. Higher commodity prices pressured margins, and also heavy fuel oil sales declined. Emera Fuel's gross margin was up $5.2 million from $8.7 million in 2002, reflecting colder weather in the first quarter of 2003 and the implementation of a "price lock" program.

EQUITY EARNINGS

Equity earnings from the Maritimes & Northeast Pipeline decreased to $1.2 million in Q4, 2004 compared to $2.1 million in Q4, 2003.

For the year ended December 31, 2004, M&NP equity earnings were $6.2 million, compared to $9.6 million in 2003. This reflects performance on the U.S. component of the pipeline, due to lower volumes, higher operating costs associated with the Phase III expansion (not currently reflected in rates) and a stronger Canadian dollar. Equity earnings were up $0.5 million in 2003 from $9.1 million in 2002, reflecting an increase in gas volumes shipped with the start of production from the Alma Field, the first of SOEP's Tier II projects.

On June 30, 2004 the Maritimes & Northeast Pipeline filed a Notice of Rate Increase for its U.S. operations. The proposed rate increase of 54% results principally from:

- A decline in reserves and deliverability associated with the Sable Offshore Energy Project fields;
- The inclusion in the rates of costs related to the Phase III expansion project, which M&NP placed into service on November 24, 2003; and
- An updated cost of service.

The rate application is scheduled for a hearing in May 2005. In the meantime, M&NP is permitted to charge and collect increased rates as of January 1, 2005. The increase is subject to refund pending the outcome of the application.

SOEP FEES

In Q4, 2003, Emera sold its 8.4% interest in the Sable Offshore Energy Project's ("SOEP") offshore platforms and sub-sea gathering lines. Accordingly, there is a reduction in SOEP processing fees and depreciation expense quarter over quarter and year over year.

ENERGY MARKETING MARGIN

Emera Energy Services net margin increased to $6.7 million in Q4, 2004, from $3.9 million in Q4, 2003 as a result of increased energy management services opportunities and a corresponding increase in marketing opportunities.

For the year ended December 31, 2004, net margin was $24.2 million compared to $11.7 million in 2003, for the reasons noted above. In 2002, the year the energy marketing operation was established, energy marketing margin was $1.9 million.

OPERATING, MAINTENANCE AND GENERAL

Other operating, maintenance and general expenses were $7.6 million in Q4, 2004, compared to $9.0 million in Q4, 2003.

For the year ended December 31, 2004, Other operating, maintenance and general expenses were $30.1 million, compared to $29.9 million in 2003, and $36.4 million in 2002. The 2002 amounts included $11.9 million in asset write-downs.

BUSINESS DEVELOPMENT

Business development costs were $0.5 million in Q4, 2004 compared to $1.3 million in Q4, 2003. For the year ended December 31, 2004, business development costs were $5.7 million compared to $8.2 million for 2003 and $17.8 million in 2002. The decreases reflect the streamlining of business development activities, including a 50% workforce reduction in the first quarter of 2003.

INTEREST

Interest expense was $2.9 million in Q4, 2004 compared to $2.6 million in Q4, 2003; and $13.2 million for the year ended December 31, 2004, compared to $14.9 million in 2003 and $16.6 million in 2002. The decrease reflects lower debt levels and lower rates on short-term debt refinanced. The reduction from 2002 also reflects the common equity issued in late 2002.

INCOME TAXES

All businesses included in Other follow the future income tax 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 impacted by withholding taxes paid on cross-border dividends and interest, completion of prior years' tax returns, and corporate tax sharing agreements.

DEBT MANAGEMENT

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

millions of dollars	Maturity	Maximum amount
Short-term		
Operating credit facility	1 Year Revolving	$ 150.0
Acquisition credit facility	1 Year Revolving	$ 400.0

EMERA CREDIT RATINGS

	DBRS		S&P		Moodys	
	2004	2003	**2004**	2003	**2004**	2003
Long-term corporate	**BBB (High)**	BBB (High)	**BBB+**	BBB+	**na**	na
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%–15% would be exposed to short-term rates. The Company manages debt terms such that the average is not less than ten years.

Consolidated Balance Sheets

As at December 31
millions of dollars

	2004	2003	2002
Total assets	**$ 3,941.7**	$ 3,890.9	$ 3,907.9
Total long-term liabilities	**$ 1,855.4**	$ 1,797.3	$ 1,610.8

Significant changes in the consolidated balance sheets of December 31, 2004 as compared to December 31, 2003 include:

- $16.4 million decrease in inventory primarily reflecting lower coal inventory at NSPI;
- $10.0 million decrease in the total receivable from Pengrowth Corporation in connection with the sale of the SOEP offshore assets reflecting the receipt of the 2004 payment;
- $46.1 million increase in deferred assets comprised of deposits related to Bellows Falls and Bear Swamp acquisitions, the implementation of Section 1100 Generally Accepted Accounting Principles, and amortization of regulatory and other deferred assets; and
- $25.7 million increase in deferred credits reflecting the implementation of the provisions of Section 1100 Generally Accepted Accounting Principles.

Significant changes in the consolidated balance sheets between December 31, 2002 and December 31, 2003 include:

- $26.6 million increase in accounts receivable, reflecting an increase in the amount of accounts receivable securitized, and the current portion of the long-term receivable from Pengrowth Corporation in connection with the sale of the SOEP assets;
- $18.9 million decrease in inventory, primarily reflecting a reduction of coal inventory, and lower fuel prices at NSPI;
- $35.0 million long-term receivable is the amount due from Pengrowth Corporation in connection with the sale of the SOEP offshore assets;
- $92.7 million increase in deferred assets reflecting the pre-2003 income tax deposit in NSPI, partially offset by amortization of defeasance costs and the impact of the strengthening Canadian dollar on BHE's balance sheet;
- $22.6 million decrease in goodwill reflecting the impact of the strengthening Canadian dollar on BHE's balance sheet;
- $129.0 million decrease in total property, plant and equipment, including construction work in progress, reflecting the sale of the SOEP assets and the impact of the strengthening Canadian dollar on BHE's balance sheet;
- $32.1 million increase in accounts payable and accrued charges reflecting increased fuel related payables; and
- $21.3 million decrease in deferred credits reflecting regular amortization.

Outstanding Share Data

Issued and Outstanding: millions of dollars	Millions of Shares	Common Share Capital
January 1, 2003	107.80	$ 1,000.2
Issued for cash under purchase plans	0.36	5.7
Options exercised under senior management share option plan	0.10	1.6
Share-based compensation	–	0.9
December 31, 2003	108.26	$ 1,008.4
Issued for cash under purchase plans	0.41	7.0
Options exercised under senior management share option plan	0.20	2.8
Share-based compensation	–	1.0
December 31, 2004	**108.87**	**$ 1,019.2**

As at January 31, 2005 the number of issued and outstanding common shares was 108,952,880.

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, through operating lines of credit, an accounts receivable securitization program and a commercial paper 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 filed a renewal preliminary debt shelf prospectuses in the amounts of $300 million and $400 million respectively that provide the Company with long-term debt access. The Company also has access to equity capital markets for both common and preferred shares.

CONSOLIDATED CASH FLOW HIGHLIGHTS

	Three months ended December 31		Year ended December 31	
millions of dollars	**2004**	2003	**2004**	2003
Net cash provided by operating activities	**$ 62.3**	$ 103.6	**$ 304.0**	$ 251.9
Net cash provided by (used in) financing activities	**60.7**	(251.1)	**(57.4)**	(184.4)
Net cash provided by (used in) investing activities	**(103.9)**	20.4	**(213.9)**	(85.2)
Increase (decrease) in cash and cash equivalents	**$ 19.1**	$ (127.1)	**$ 32.7**	$ (17.7)

Consolidated net cash provided by operating activities was $62.3 million in Q4, 2004, compared to $103.6 million in Q4, 2003 reflecting higher fuel costs in NSPI.

Consolidated net cash provided by operating activities was $304.0 million for 2004 compared to $251.9 million for 2003. Cash flow for the first six months of 2003 was reduced by a total of $133.0 million deposited with CRA relating to pre-2003 income taxes. The year over year positive impact was reduced by the reasons noted above.

Consolidated net cash used in financing activities decreased by $311.8 million quarter over quarter, reflecting the 2003 $150.0 million debenture retirement utilizing short-term investments, the cash flows associated with the long-term financing of the SOEP asset sale, and an increase in short-term debt. Consolidated net cash flows used in financing activities for 2004 decreased $127.0 million, which also reflects an increase in use of the accounts receivable securitization program.

Consolidated net cash used in investing activities increased $124.3 million in Q4 and $128.7 million for the year, reflecting deposits made on the pending acquisitions of Bellows Falls and Bear Swamp. The Q4, 2003 comparative amount also includes the sale of the SOEP-related assets.

PREFERRED SHARE REPURCHASE BY BANGOR HYDRO

In Q1, 2003 Bangor Hydro repurchased all of its 4% and 4.25% series of callable preferred shares and approximately 70% of its 7% non-callable preferred shares for a total cash cost of approximately $6.9 million. This was substantially financed with cash flow.

CONTRACTUAL OBLIGATIONS

millions of dollars	Payments Due by Period				
	Total	2005	2006–2007	2008–2009	After 2009
Long-term debt	$ 1,727.3	$ 370.8	$ 115.9	$ 252.0	$ 988.6
Operating leases	35.4	5.4	10.8	10.8	8.4
Purchase obligations	2,062.6	450.0	485.6	421.3	705.7
Other long-term obligations	310.0	–	0.5	–	309.5
Total contractual obligations	$ 4,135.3	$ 826.2	$ 612.8	$ 684.1	$ 2,012.2

CAPITAL RESOURCES

Capital expenditures for 2004 were approximately $150 million, including:

- $11 million on the installation of a second 50 MW natural gas fired combustion turbine in NSPI;
- $27 million to construct a marine terminal to enable NSPI access to international coal basins; and
- $20 million to install automated meter-reading technology in BHE.

Emera's capital budget for 2005 includes approximately $112 million for NSPI, which will be spent on planned and preventative maintenance and productivity-related investments; and approximately $30 million for BHE, for several major transmission line projects.

The Company expects to fund its capital expenditures with funds from operations and short-term debt.

OFF-BALANCE SHEET ARRANGEMENTS

NSPI is responsible for managing a portfolio of approximately $1.1 billion of defeasance securities held in trust, which arose in the course of the privatization of the company in 1992. The defeasance securities must provide the principal and interest streams of the related defeased debt. Approximately 69%, or $735 million, 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 major Canadian chartered bank whereby it can sell accounts receivable to the trust on a revolving basis. As of December 31, 2004, the company had sold $80.0 million of net accounts receivable (2003 – $50.0 million). 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, 2004, the average all-in cost of this funding was 2.64% (2003 – 3.52%). 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 options and swaps, and oil and gas options and swaps.

Hedges 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 hedges are marked-to-market and recognized in earnings in the reporting period.

As at December 31, 2004, the Company had deferred payments and receipts on derivative instruments that are designated and effective as hedges and are recognized in the following categories in the balance sheet:

DEFERRED HEDGING LOSSES (GAINS) RECOGNIZED ON THE BALANCE SHEET

millions of dollars	
Deferred charges	$ 0.1
Inventory	1.6
Accounts payable and accrued charges	(0.3)
Deferred hedging losses	$ 1.4

For the three-month period and year ended December 31, 2004, the impacts of effective hedges recognized in earnings were recorded in the following categories:

HEDGING IMPACT RECOGNIZED IN EARNINGS

millions of dollars	Q4 2004	YTD 2004
Fuel and purchased power increase	$ (3.7)	$ (4.9)
Interest expense increase	(1.1)	(5.0)
Hedging earnings impact	$ (4.8)	$ (9.9)

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.

As at December 31, 2004 the Company had recorded the following marked-to-market transactions included in the balance sheet and recognized in earnings.

MARKED-TO-MARKET GAINS RECOGNIZED ON THE BALANCE SHEET

millions of dollars	
Energy marketing assets	$ 10.3
Energy marketing liabilities	(9.4)
Marked-to-market gains	$ 0.9

MARKED-TO-MARKET GAINS (LOSSES) RECOGNIZED IN EARNINGS

millions of dollars	Q4 2004	YTD 2004
Other revenue	$ 0.8	$ 0.9
Fuel and purchased power	(3.3)	–
Marked-to-market gains	$ (2.5)	$ 0.9

In determining the fair value of derivative financial instruments, the Company has relied on quoted market prices as of December 31, 2004.

Transactions With Related Parties

In the ordinary course of business, in Q4, 2004, Emera purchased transportation capacity totalling $10.1 million (Q4, 2003 – $13.1 million) from the Maritimes & Northeast Pipeline, an investment under significant influence of the Company. For the year ended December 31, 2004, the amount purchased was $45.4 million (2003 – $48.0 million). The amount is recognized in fuel for generation, or netted against energy marketing margin in other revenue, and is measured at the exchange amount. At December 31, 2004 the amount payable to the related party is $3.2 million (2003 – $3.9 million).

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 pension and other employee benefits, unbilled revenue, asset retirement obligations, useful lives for depreciable assets, and 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 and generally involves 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 as 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 the actual experience for 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 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 provisions 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. If both the expected rate of return on plan assets and the discount rate were increased by 0.5%, the impact on the 2005 benefit cost and accrued benefit asset and liability recorded in the year end consolidated financial statements would be as follows:

			2004	
millions of dollars		NSPI		BHE
Impact of increasing the rate of return assumption by 0.5%:				
Benefit cost	$	(2.7)	$	(0.3)
Accrued benefit asset	$	2.7		–
Accrued benefit liability		–	$	(0.3)
Impact of increasing the discount rate assumption by 0.5%:				
Benefit cost	$	(5.0)	$	(0.1)
Accrued benefit pension asset	$	5.0		–
Accrued benefit pension liability		–	$	(0.1)

The discount rate is based on long-term Canadian corporate bonds for NSPI's pension plan and US corporate bonds for BHE's pension plan, which have the same duration as the accrued benefit obligation as of the end of the fiscal year rounded to the nearest 25 basis points. NSPI's rate was 6.0% for 2003 and 2004 and BHE's rate was reduced from 6.75% in 2002 to 6.25% in 2003 and 2004. The expected rate to be used for 2005 is 6.00% for NSPI and 6.00% for BHE.

The expected rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. The 2003 and 2004 benefit cost calculations assumed that plan assets would earn a rate of return of 7.5% for NSPI and 8.0% for BHE. The 2005 benefit cost calculation is expected to use these 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 of their last meter reading 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, 2004, unbilled revenues amount to $66.4 million on a base of annual electric revenues of approximately $1.1 billion.

During 2003, the Company improved its process for estimating its unbilled revenue. The change resulted in reductions in unbilled revenue accruals, with corresponding charges against revenues as follows:

- NSPI $10.0 million ($6.5 million after-tax); and
- BHE $3.2 million ($1.9 million after-tax).

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, dismantling, restoration and remedial work based on present-day methods and technologies.

In 2003, the UARB approved the amount of future expenditures associated with the removal of generation facilities for NSPI. 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, 2004, the asset retirement obligations recorded on the balance sheet were $68.5 million (2003 – $65.1 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $310 million, which will be incurred between 2005 and 2061. The majority of these costs will be incurred between 2020 and 2039.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment represents 70% 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 at the direction of the UARB. The Study was filed with the UARB in 2003, following which a stakeholder consultation process was conducted. A settlement agreement on the matter was reached with all intervenors, which recommended an increase in depreciation expense of $5.0 million per year beginning in 2004, to reach an overall increase of $20 million by 2007. The UARB approved the settlement. NSPI's next depreciation study is scheduled for 2006.

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 depreciation study results 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 its composite depreciation rates for 2004 to reflect shorter lives as recommended by the study. The net result was a $0.8 million increase in 2004 depreciation expense.

GOODWILL IMPAIRMENT ASSESSMENTS

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.

Change in Accounting Policies

In 2004, the Company adopted the new accounting standard related to asset retirement obligations, the new accounting guideline related to hedging relationships, and the new Handbook Section 1100 Generally Accepted Accounting Principles (GAAP) that disallows industry practice as acceptable GAAP. There were no changes in accounting policies during 2003.

ASSET RETIREMENT OBLIGATIONS

In 2004, the Company retroactively adopted the new accounting standard related to asset retirement obligations. Previously the Company had accrued its obligations in annual increments based on the expected settlement date of the obligation using estimated current costs. The new standard requires the Company to determine the fair value of the future expenditures required to settle legal obligations to remove fixed assets. The present value of this estimated future expenditure is recognized as a liability with an equivalent amount added to the carrying amount of the associated fixed asset.

As a result of adopting the new standard, as at December 31, 2003, property, plant and equipment have increased by $44.4 million, regulatory assets have increased by $0.3 million (see discussion in accounting policy for rate-regulated companies below), and asset retirement obligations have increased by $44.7 million. The impact of the change on 2004 net earnings was a decrease to depreciation expense of $0.4 million (2003 – nil).

Some of the Company's transmission and distribution assets may also have 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.

Rate-regulated accounting:
Any difference between the amount approved by the regulators of Nova Scotia Power and Bangor Hydro as depreciation expense and the amount that would have been calculated under the new accounting standard is recognized as a regulatory asset in property, plant and equipment. Differences are deferred and will be included in future depreciation studies.

HEDGING RELATIONSHIPS

In 2004, the Company prospectively adopted the new accounting guideline related to hedging relationships. The Company is now documenting and testing the effectiveness of its hedging relationships in accordance with the new guideline. Where the new requirements are not met, the hedging items are marked-to-market. The adoption of this guideline had no impact on 2004 net earnings.

SECTION 1100

In 2004, the Company prospectively adopted the new CICA Handbook Section 1100 Generally Accepted Accounting Principles ("GAAP") that disallows industry practice as acceptable GAAP. In previous years, the Company did not recognize offsetting regulatory liabilities and assets that arose in the Company's rate regulated subsidiary, Bangor Hydro-Electric Company. These assets and liabilities are now recognized in the financial statements. As a result, as at December 31, 2004, deferred charges and deferred credits have both increased by $33.1 million. There has been no impact on net earnings.

Dividend Policy and Payout Ratios

Emera Inc.'s common dividend rate was $0.88 ($0.22 per quarter) per common share in 2004 and $0.86 ($0.215 per quarter) per common share in 2003, representing a payout ratio of approximately 73%. In January 2005, the Board of Directors increased the 2005 common share dividend to $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 Executive Risk Management Committee to ensure that risks are appropriately assessed, monitored and controlled within predetermined risk tolerances established through Board 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 and interest rates.

Commodity Prices

Substantially all of the Company's annual fuel requirement for 2005 is subject to fluctuations in commodity market prices, prior to any commodity price risk management activities.

Coal/Petroleum Coke

Substantially all 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 coal suppliers to ensure reliability of both fuel supply and price. Physical contracts are used to hedge coal price risk due to the lack of liquidity in the financial markets for coal. Approximately 85% of coal and petroleum coke requirements for 2005 had been contracted as at December 31, 2004.

Heavy Fuel Oil

Emera manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options and futures contracts. As at December 31, 2004, the price for approximately 50% of heavy fuel oil purchases for 2005 had been contracted.

Natural Gas

The Company has entered into two multi-year contracts to purchase approximately 65 million cubic feet of natural gas per day. One contract that covers over 60 million cubic feet per day was subject to a price reopening in Q4, 2004 and is currently in arbitration. It is anticipated that the outcome will result in the majority of gas volumes under this contract being more exposed to market fluctuations. The volumes exposed to market prices will be managed using financial instruments where required for generation; and sold against floating 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 also using financial instruments. Approximately 70% of 2005 gas sales and purchases had been hedged as of December 31, 2004.

Fuel Mix

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.

Foreign Exchange

In 2005, the Company expects approximately 80% of its anticipated net fuel costs to be denominated in U.S. dollars, as $US income from sales of surplus natural gas will provide a natural hedge against a portion of $US denominated fuel costs. Forward and option contracts are used to manage the exposure to fluctuating $US exchange rates. Forward contracts are in place for approximately 65% of 2005 anticipated $US net fuel costs.

Payments in $US received from the U.S. portion of our investment in the Maritimes & Northeast Pipeline will be used to repay $US debt.

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 20% of total debt in 2004. Interest forward rate agreements and swaps are used to fix rates on part of the floating rate debt, while interest rate caps are used to limit exposure to movements of interest rates on floating debt. For 2005, interest on approximately 12% of the Company's anticipated floating debt is fixed at an average rate of 6.81% and another 24% is capped at a rate of 3.45%.

Interest rate collars are used to partially hedge reinvestment risk on long-term fixed-rate debt. Fixed-rate debt maturities are limited in any one year and continually monitored to reduce rollover exposure. For 2005 approximately 20% of the Company's maturing long-term fixed-rate debt has been collared at rates of 4.89%–5.30%.

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 upon the Board of

Directors' approved credit policies. The corporation frequently uses collateral agreements within its negotiated master agreements to further mitigate credit exposure.

Regulatory Risk

In December 2001, the Nova Scotia government released *Seizing the Opportunity: Nova Scotia's Energy Strategy*. The strategy for the electricity industry is to carefully increase competition over a prudent time frame. In addition, consistent with recommendations put forward by Emera, the strategy indicates government will provide policy direction to the UARB to authorize open access transmission on NSPI facilities, and introduce competition in the wholesale market by 2005. The wholesale market comprises six municipal electric utilities, and represents approximately 1.6% of NSPI's revenues. These two recommendations will help Nova Scotia meet United States and other Canadian market reciprocity requirements, and thus facilitate electricity exports.

An Electricity Marketplace Governance Committee ("EMGC") was established to recommend to the Minister of Energy the implementation, development, structure and rules for the future electricity sector. During 2003, EMGC concluded its work and the Nova Scotia Government has accepted its recommendations in principle. Its report provides no material change to the Province's energy strategy.

Broader restructuring of the electricity industry in Nova Scotia is not on the horizon in the medium term. The province's geographic location, the limits of inter-provincial transmission links, and the diversity of our customer base will help to reduce the impact of a more significant move to restructuring on NSPI. In addition, the company is committed to enhancing its strong competitive and financial position by:

- managing costs through enhanced capacity management, reduced fuel and operating costs and efficient capital investment;
- working with customers to help them reduce energy costs, including providing them with greater access to time-of-use pricing; and
- continuously improving customer service.

Labour

In June 2004 NSPI reached a 52 month agreement with 800 employees. This brings labour stability to the organization well into 2007.

Bangor Hydro's contract with its unionized employees expires at the end of 2005. Negotiations are currently underway, and based on approach to date and outstanding issues, the company does not anticipate any labour disruption in 2005.

Environmental Protection

Corporate Environmental Governance

Emera is committed to meeting its business objectives in a manner that is respectful and protective of the environment, and in full compliance with legal requirements and company policy. For several years, Emera and its wholly-owned subsidiaries have implemented this policy through development and application of environmental management systems ("EMS"). The program continued in 2004 with alignment of EMS objectives across the organization.

Conformance with legislative and Company requirements is verified through an extensive environmental audit program. The 2004 program included several Emera subsidiaries and maintained an objective to review all wholly-owned operations within a three-year cycle. Where non-conformity is identified, effective action strategies are developed and implementation costs closely monitored.

The Board of Directors' Environment, Safety and Security Committee met several times throughout 2004 and continued to carry out its oversight role in ensuring that an appropriate focus is placed on environmental protection. The Emera Environmental Council, made up of senior employees with working accountability for environment, continues to guide the implementation of programs that address key environmental issues.

Atmospheric Emissions

In 2004 the government of Nova Scotia proposed a number of amendments to the Air Quality Regulations under the Nova Scotia Environment Act. Beginning in 2005 and through the end of the decade, the amendments require substantial reductions of sulphur dioxide (SO_2), oxides of nitrogen (NOx) and mercury emitted from Nova Scotia Power facilities. NSPI will meet its 2005 limits, and implementation plans are being prepared to address medium-term requirements based on an Air Emissions Strategy which comprehensively deals with the entire suite of air emissions, including those linked to climate change.

When the Canadian government ratified the Kyoto Protocol, it set an aggressive greenhouse gas reduction target for the country. Emera supports prudent Canadian abatement efforts and continues to work with the federal and provincial governments to develop an implementation plan that considers the potential impacts on the Company and its customers.

SUMMARY OF QUARTERLY REPORTS

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

	Dec 31 2004	Sep 30 2004	Jun 30 2004	Mar 31 2004	Dec 31 2003	Sep 30 2003	Jun 30 2003	Mar 31 2003
Total revenues	$309.4	$276.0	$287.2	$347.4	$310.3	$281.0	$284.8	$355.2
Net earnings applicable to common shares	$ 31.4	$ 22.1	$ 29.8	$ 46.5	$ 47.5	$ 11.5	$ 15.5	$ 54.7
Earnings per common share – basic	$ 0.30	$ 0.20	$ 0.27	$ 0.43	$ 0.44	$ 0.11	$ 0.14	$ 0.51
Earnings per common share – diluted	$ 0.28	$ 0.20	$ 0.27	$ 0.41	$ 0.43	$ 0.11	$ 0.14	$ 0.47

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.

2003 quarterly net earnings applicable to common shares were also affected by the following:

- In 2003 the Company improved its process for estimating its unbilled revenue. The change resulted in reductions in unbilled revenue accruals of $10.0 million ($6.5 million after-tax) in Q2 for NSPI and $3.2 million ($1.9 million after-tax) in Q3 for BHE, with corresponding changes against revenue.
- In Q3, 2003 Nova Scotia was struck by Hurricane Juan, a Category Two hurricane causing extensive damage to NSPI's transmission and distribution system. The total cost of the hurricane to the Company was $12.6 million, specifically $4.0 million of net operating costs that were recorded in Q3, and $8.6 million in capital costs.
- Prior to 2003, Nova Scotia Power revised its site restoration accrual for the Glace Bay generating station as the actual costs were expected to be lower than estimated. As a result, depreciation expense was decreased by $3.8 million in Q4, 2004.

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 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 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 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 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.

January 31, 2005

Christopher G. Huskilson
President and Chief Executive Officer

Randy Henderson, CA
Senior Vice-President and Chief Financial Officer

TO THE SHAREHOLDERS OF EMERA INC.

We have audited the consolidated balance sheets of Emera Inc. as at December 31, 2004 and 2003, 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, 2004 and 2003 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
January 31, 2005

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants

Consolidated Statements of Earnings

Year Ended December 31 millions of dollars (except earnings per common share)	2004	2003 (restated – see note 3)
Revenue		
Electric	$ 1,095.7	$ 1,104.1
Fuel oil	87.8	84.5
Other	38.5	42.7
	1,222.0	1,231.3
Cost of operations		
Fuel for generation and purchased power	350.0	363.3
Cost of fuel oil sold	75.0	71.5
Operating, maintenance and general	254.6	269.4
Grants in lieu of property taxes	37.7	33.1
Provincial capital tax	8.6	7.8
Depreciation	132.0	127.7
	857.9	872.8
Earnings from operations	364.1	358.5
Equity earnings (note 7)	6.2	8.6
Regulatory amortization	(26.1)	(18.2)
Allowance for funds used during construction	4.0	5.1
Earnings before interest and income taxes	348.2	354.0
Interest (note 8)	126.8	133.6
Amortization of defeasance costs	15.1	16.7
Earnings before income taxes	206.3	203.7
Income taxes (note 9)	63.1	61.3
Net earnings before non-controlling interest	143.2	142.4
Non-controlling interest (notes 10 and 21)	13.4	13.2
Net earnings applicable to common shares	$ 129.8	$ 129.2
Earnings per common share – basic (note 11)	$ 1.20	$ 1.20
Earnings per common share – diluted (note 11)	$ 1.16	$ 1.15

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Retained Earnings

Year Ended December 31 millions of dollars	2004	2003 (restated – see note 3)
Retained earnings, beginning of year	$ 365.3	$ 328.9
Net earnings applicable to common shares	129.8	129.2
	495.1	458.1
Dividends	95.5	92.8
Retained earnings, end of year	$ 399.6	$ 365.3

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheets

Year Ended December 31 millions of dollars	2004	2003
Assets		(restated – see note 3)
Current assets		
Cash and cash equivalents	$ 42.7	$ 10.0
Restricted cash	18.2	6.9
Accounts receivable (note 12)	176.1	182.9
Income tax receivable	2.4	1.4
Inventory	73.4	89.8
Prepaid expenses	5.4	6.2
Future income tax assets (note 9)	1.0	0.6
Energy marketing assets	10.3	7.7
	329.5	305.5
Long-term receivable (note 13)	20.0	35.0
Deferred charges (note 14)	575.3	528.9
Future income tax assets (note 9)	34.1	26.6
Goodwill (note 17)	107.7	115.1
Investments (note 7)	96.8	102.8
Property, plant and equipment (note 15)	2,714.6	2,715.1
Construction work in progress	63.7	61.9
	2,778.3	2,777.0
	$ 3,941.7	$ 3,890.9
Liabilities and Shareholders' Equity		
Current liabilities		
Current portion of long-term debt (note 20)	$ 100.8	$ 166.3
Short-term debt (note 19)	145.4	129.2
Accounts payable and accrued charges	228.5	214.1
Income tax payable	1.4	–
Dividends payable	3.2	3.2
Energy marketing liabilities	9.4	7.4
	488.7	520.2
Future income tax liabilities (note 9)	79.6	87.6
Asset retirement obligations (note 18)	68.5	65.1
Deferred credits (note 14)	80.8	55.1
Long-term debt (note 20)	1,626.5	1,589.5
Non-controlling interest (note 21)	260.8	260.8
Shareholders' equity		
Common shares (note 22)	1,019.2	1,008.4
Foreign exchange translation adjustment (note 24)	(82.0)	(61.1)
Retained earnings	399.6	365.3
	1,336.8	1,312.6
	$ 3,941.7	$ 3,890.9

Contingencies (note 14), Commitments (note 27), Guarantees (note 28).

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors

Derek Oland
Chairman

Christopher G. Huskilson
President and Chief Executive Officer

Consolidated Statements of Cash Flows

Year Ended December 31 millions of dollars	2004	2003 (restated – see note 3)
Operating activities		
Cash received from customers	$ 1,209.5	$ 1,232.6
Cash paid to suppliers and employees	(691.6)	(668.9)
Cash provided by operations, before interest and taxes	517.9	563.7
Interest paid	(130.8)	(127.9)
Income taxes and capital taxes paid	(83.1)	(50.9)
Pre-2003 income tax assessment	–	(133.0)
Net cash provided by operating activities (note 26)	304.0	251.9
Financing activities		
Increase in (reduction of) short-term debt	165.6	(180.5)
Issue of common shares	9.8	7.3
Repurchase of preferred shares by subsidiary	–	(7.2)
Issue of long-term debt	–	368.1
Retirements of long-term debt	(165.3)	(197.6)
Dividends paid on common shares	(95.5)	(92.9)
Cash paid to non-controlling interest	(14.1)	(14.2)
Long-term financing of asset sale	10.0	(45.0)
Accounts receivable securitization	30.0	(25.0)
Other financing activities	2.1	2.6
Net cash used in financing activities	(57.4)	(184.4)
Investing activities		
Property, plant and equipment	(151.6)	(121.2)
Proceeds from sale of fixed assets	1.7	72.4
Investments	(48.0)	(27.3)
Retirement spending	(4.7)	(3.0)
Decrease (increase) in restricted cash	(11.3)	(6.1)
Net cash used in investing activities	(213.9)	(85.2)
Increase (decrease) in cash and cash equivalents	32.7	(17.7)
Cash and cash equivalents, beginning of year	10.0	27.7
Cash and cash equivalents, end of year	$ 42.7	$ 10.0
Cash and cash equivalents consists of:		
Cash	$ 24.8	$ 6.3
Short-term investments	17.9	3.7
Cash and cash equivalents, end of year	$ 42.7	$ 10.0

See accompanying notes to the consolidated financial statements.

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. NSPI is regulated by the Nova Scotia Utility and Review Board ("UARB"). BHE is regulated by the Federal Energy Regulatory Commission ("FERC") and the Maine Public Utilities Commission ("MPUC"). The regulators exercise statutory authority over matters such as construction, rates, and underlying accounting policies.

Emera follows Canadian generally accepted accounting principles ("GAAP"). NSPI's accounting policies are subject to examination and approval by the UARB and are similar to those being used by other companies in the electric utility industry in Canada. Bangor Hydro's accounting policies are subject to examination and approval by FERC and the MPUC and are similar to those being used by other companies in the electric utility industry in Maine. The rate-regulated accounting policies 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, estimate 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.
- Fuel Oil: Revenues are recognized on delivery of product.
- 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.

d. Allowance for Funds Used during Construction

Rate-regulated accounting policy:
For the regulated electric businesses carried on by NSPI and Bangor Hydro, the Company provides 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. The allowance will be charged to operations through depreciation over the service life of the related assets and recovered through future revenues.

e. Regulatory Amortization

Rate-regulated accounting policy:
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 services 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 8, 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.

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 2004 to 2018 through charges to earnings. These regulatory assets and liabilities include costs related to terminating/restructuring purchased power contracts, the Seabrook nuclear project, decommissioning costs for Maine Yankee, and obligations to Hydro-Quebec, and are described in more detail in note 14.

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 live for the Company's unregulated assets is 14 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 an impairment exists, include significant changes in regulation, a change in the Company's strategy or underperformance relative to projected future operating results.

Rate-regulated accounting policy:
During 2003, following completion of a depreciation study, and a negotiated agreement with stakeholders, NSPI's regulator approved new depreciation rates, which will be phased in over four years beginning in 2004. Depreciation is now computed on the straight-line basis over the estimated remaining services lives of depreciable assets in each category based on the phase-in period contained within the Settlement Agreement. The full impact on depreciation expense will increase by $5.0 million per year beginning in 2004, to reach an overall increase of $20 million by 2007.

The average rates for the major categories of plant in service are summarized as follows:

FUNCTION

	2004	2003
Generation		
Thermal	2.38%	2.33%
Gas turbine	2.18%	2.04%
Combustion turbines	5.00%	5.00%
Hydro-electric	1.26%	1.18%
Wind turbine	5.00%	5.00%
Transmission	2.68%	2.71%
Distribution	3.96%	3.82%
General plant	6.21%	5.28%
Weighted average depreciation rate	3.07%	2.89%

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

FUNCTION

	2004	2003
Transmission	42	49
Distribution	40	40
Other	15	20
Weighted average service life	34	40

In accordance with regulator approved accounting policies, when 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.

g. 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.

Rate-regulated accounting policy:
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.

h. 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 prorated 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 asset gains and losses 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 average remaining service period ("ARSP") of 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 ARSP is amortized on a straight-line basis. The ARSP of the active employees is 10 years as at December 31, 2004 (2003 – 11 years). For Bangor Hydro this excess is amortized on a straight-line basis over the expected ARSP.

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 pension expense and pension funding is recorded as a deferred asset or credit on the balance sheet.

i. 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 units plan, and a restricted share units plan. The Company accounts for its plans in accordance with the fair-value-based method of accounting for share-based compensation.

j. 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 2.37% at December 31, 2004 (December 31, 2003 – 0.44%).

k. Inventory

Inventories of materials and supplies are valued at the lower of average cost and market. Coal and oil inventory is valued at the lower of cost, using the first-in, first-out method, and net realizable value.

l. Debt Financing and Defeasance Costs

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

NSPI is responsible for managing a portfolio of approximately $1.1 billion of defeasance securities held in trust, which arose in the course of the privatization of the company in 1992. 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.

m. 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.

n. 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.

o. Long-Term Investments

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, Maine Electric Power Company Inc., Greyhawk Natural Gas Storage, and Intragas Energy using the equity method.

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

p. 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.

q. Research and Development Costs

All research and development costs are expensed in the year incurred unless they can be deferred as a part of capital assets.

2. CHANGE IN ACCOUNTING ESTIMATE

Electric revenues are recognized on the accrual basis, which includes an estimate of electricity consumed by customers in the period but billed subsequent to the period. During the second quarter 2003, the Company's subsidiary, Nova Scotia Power Inc., improved its process for estimating unbilled revenue and as a result, decreased its electric revenue by approximately $10.0 million. During the third quarter 2003, the Company's subsidiary, Bangor Hydro-Electric Company improved its process for estimating unbilled revenue and as a result, decreased its electric revenue by approximately $3.2 million.

3. CHANGE IN ACCOUNTING POLICIES

Asset Retirement Obligations

In January 2004, the Company retroactively adopted the Canadian Institute of Chartered Accountants' ("CICA") new accounting standard, Handbook Section 3110, related to asset retirement obligations. Previously the Company had accrued its obligations in annual increments based on the expected settlement date of the obligation using estimated current costs. The new standard requires the Company to determine the fair value of the future expenditures required to settle legal obligations to remove fixed assets. The present value of this estimated future expenditure was recognized as a liability with an equivalent amount added to the carrying amount of the associated fixed asset.

As a result of adopting the new standard, as at December 31, 2003, results have been restated and property, plant and equipment have increased by $44.4 million, regulatory assets have increased by $0.3 million, and asset retirement obligations have increased by $44.7 million. The impact to net earnings was a decrease in depreciation expense of $0.4 million (2003 – nil).

Hedging Relationships

In 2004, the Company prospectively adopted the CICA's new accounting guideline, AcG-13, related to hedging relationships. The Company is now documenting and testing the effectiveness of its hedging relationships in accordance with the new guideline. Where the new requirements are not met, the hedging items are marked-to-market. There was no impact on 2004 net earnings.

Section 1100

In January 2004, the Company prospectively adopted the new provisions of the Canadian Institute of Chartered Accountants' Handbook Section 1100 Generally Accepted Accounting Principles ("GAAP") that disallows industry practice as acceptable GAAP. In previous years, offsetting regulatory liabilities and assets arose in the Company's rate regulated subsidiary, Bangor Hydro, which the Company did not recognize. These assets and liabilities are now recognized in the financial statements. As a result, as at December 31, 2004, deferred charges and deferred credits have increased by $33.1 million. There has been no impact to net earnings.

4. 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 reportable segments are the same as those described in the summary of significant accounting policies.

Reportable 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 fuel oil sales, energy marketing margin, and, in 2003, processing fees earned on the Company's interest in the offshore platforms and sub-sea gathering lines of the Sable Offshore Energy Project.

millions of dollars	Nova Scotia Power		Bangor Hydro		Other*		Total	
	2004	2003	2004	2003	2004	2003	2004	2003
Revenues from external customers	$ 933.8	$ 900.2	$ 168.6	$ 200.1	$ 119.6	$ 131.0	$ 1,222.0	$ 1,231.3
Depreciation	116.0	101.7	14.0	13.5	2.0	12.5	132.0	127.7
Cost of operations, including depreciation	636.1	598.9	107.0	143.0	114.8	130.9	857.9	872.8
Net inter-segment revenues/ (expenses)	153.0	96.5	(2.1)	(1.9)	(150.9)	(94.6)	–	–
Equity earnings	–	–	–	–	6.2	8.6	6.2	8.6
Interest expense	100.1	104.3	13.5	14.4	13.2	14.9	126.8	133.6
Income taxes	59.2	57.8	10.2	12.5	(6.3)	(9.0)	63.1	61.3
Net earnings applicable to common shareholders	107.3	112.1	18.5	18.8	4.0	(1.7)	129.8	129.2
Segment assets	2,987.9	3,004.8	599.8	608.0	354.0	278.1	3,941.7	3,890.9
Segment goodwill	–	–	99.3	106.7	8.4	8.4	107.7	115.1
Capital expenditures	142.5	94.0	37.8	26.4	(28.7)	0.8	151.6	121.2

*Other consists of items related to corporate activities and other subsidiaries.

5. 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, 2004.

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 the following:

	Most recent actuarial valuation	Next required actuarial valuation
Employee pension plan	December 31, 2004	December 31, 2007
Acquired companies pension plan	December 31, 2004	December 31, 2007

Total Cash Amount

Total cash amount for 2004, 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 $34.2 million (2003 – $22.7 million).

ACCRUED PENSION AND NON-PENSION BENEFIT ASSET (LIABILITY)

	2004		2003	
millions of dollars	Defined-benefit pension plans	Non-pension benefits plans	Defined-benefit pension plans	Non-pension benefits plans
Assumptions (weighted average)				
Accrued benefit obligation – December 31:				
Discount rate	6.0%	6.0%	6.0%	6.0%
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	–	10.0%	–	11.0%
– ultimate	–	4.0%	–	4.0%
– year ultimate reached	–	2010	–	2010
Benefit cost for year ending December 31:				
Discount rate	6.0%	6.0%	6.5%	6.5%
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	–	11.0%	–	12.0%
– ultimate	–	4.0%	–	4.0%
– year ultimate reached	–	2010	–	2010
Accrued benefit obligations				
Balance, January 1	$ 624.0	$ 31.2	$ 549.8	$ 33.7
Employer current service cost	10.0	1.2	8.6	1.2
Employee contributions	5.0	–	4.7	–
Interest cost	36.8	1.9	35.2	2.2
Past service amendments	(7.3)	–	6.1	–
Actuarial losses (gains)	1.3	(1.4)	48.3	(4.5)
Benefits paid	(29.5)	(1.8)	(28.7)	(1.4)
Balance, December 31	$ 640.3	$ 31.1	$ 624.0	$ 31.2
Fair value of plan assets				
Balance, January 1	$ 471.3	$ –	$ 406.8	$ –
Employee contributions	5.0	–	4.7	–
Employer contributions	31.6	1.8	20.6	1.4
Actual investment income	37.6	–	67.9	–
Benefits paid	(29.5)	(1.8)	(28.7)	(1.4)
Balance, December 31	$ 516.0	$ –	$ 471.3	–
Reconciliation of financial status to accrued benefit asset, December 31				
Fair value of plan assets	$ 516.0	$ –	$ 471.3	$ –
Accrued benefit obligations	640.3	31.1	624.0	31.2
Plan deficit	$ (124.3)	$ (31.1)	$ (152.7)	$ (31.2)
Unamortized past service (gains) costs	(0.6)	–	7.0	–
Unamortized actuarial losses (gains)	191.3	(5.2)	196.8	(4.1)
Unamortized transitional obligation	0.2	17.9	0.2	20.1
Accrued benefit asset (liability)	$ 66.6	$ (18.4)	$ 51.3	$ (15.2)

The expected return on plan assets is determined based on the market-related value of plan assets of $519.8 million at January 1, 2004 (January 1, 2003 – $506.2 million), adjusted for interest on certain cash flows during the year.

DEFINED BENEFIT PLANS ASSET ALLOCATION

	2004		2003	
percent of plan assets	Employee pension plan	Acquired companies pension plan	Employee pension plans	Acquired companies pension plan
Equity securities	67%	56%	65%	60%
Debt securities	31%	41%	32%	39%
Cash	2%	3%	3%	1%
Total	100%	100%	100%	100%

As at December 31, 2004, 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, 2004, all post-retirement benefit plans have accrued pension obligations in excess of assets.

BENEFITS EXPENSE

	2004		2003	
millions of dollars	Defined-benefit pension plans	Non-pension benefits plan	Defined-benefit pension plans	Non-pension benefits plan
Defined benefit plan				
Costs arising from events during the year:				
Current service costs	$ 10.0	$ 1.2	$ 8.6	$ 1.2
Interest on accrued benefits	36.8	1.9	35.2	2.2
Less: actual return on plan assets	(37.6)	–	(67.9)	–
Actuarial losses (gains) on accrued benefit obligation	1.3	(1.4)	48.3	(4.5)
Past service costs (gains)	(7.3)	–	6.1	–
Future benefit costs before adjustments	$ 3.2	$ 1.7	$ 30.3	$ (1.1)
Adjustments to recognize long-term nature of costs:				
Difference between expected return on assets and actual return	(1.1)	–	30.0	–
Amortization of transitional obligation	–	2.2	–	2.2
Difference between amortization of actuarial losses (gains) and actual actuarial losses (gains) on accrued benefit obligations	6.5	1.1	(45.7)	4.6
Difference between amortization of past service costs and past service costs for the year	7.6	–	(5.8)	–
Total benefits expense	$ 16.2	$ 5.0	$ 8.8	$ 5.7
Defined contribution plan				
Employer expense	$ 0.8	$ –	$ 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 the following impact in 2004:

millions of dollars	Increase	Decrease
Current service cost and interest cost	$ 0.2	$ (0.1)
Accrued benefit obligation, December 31	$ 1.7	$ (1.4)

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.

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, 2004.

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	January 1, 2004	January 1, 2005

Total Cash Amount

Total cash amount for 2004, 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 $6.5 million (2003 – $5.6 million).

CORRECTION NOTICE

March 17, 2005

Subsequent to the release of Emera's 2004 financial results on February 11, 2005, but prior to the mailing of the 2004 Annual Financial Report, the Company discovered clerical errors in Note 5 to the financial statements "Employee Future Benefits". The errors occurred in the Bangor Hydro section of Note 5, on pages 53 and 54. **These clerical errors affected Footnote 5 only, and did not affect reported earnings, cash flows or financial position.** Corrected information is reproduced below, with changes highlighted in enlarged italic type.

PAGE 53 - ACCRUED PENSION AND NON-PENSION BENEFIT LIABILITY

	2004		2003	
	Defined-benefit pension plans	**Non-pension benefits plans**	Defined-benefit pension plans	Non-pension benefits plans
Assumptions (weighted average)				
Accrued benefit obligation – December 31:				
Discount rate	**6.00%**	**6.00%**	6.25%	6.25%
Rate of compensation increase	**4.00%**	**4.00%**	4.00%	4.00%
Health care trend - initial	**-**	**12.00%**	-	9.00%
- ultimate	**-**	**5.00%**	-	5.00%
- year ultimate reached	**-**	**2010**	-	2008
Benefit cost for year ending December 31:				
Discount rate	**6.25%**	**6.25%**	6.75%	6.75%
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	**-**	**12.00%**	-	9.00%
- ultimate	**-**	**5.00%**	-	5.00%
- year ultimate reached	**-**	**2010**	-	2008

PAGE 54 – BENEFITS EXPENSE

	2004		2003	
	Defined-benefit pension plans	**Non-pension benefits plans**	Defined-benefit pension plans	Non-pension benefits plans
Defined benefit plan				
Costs arising from events during the year:				
Current service costs	**$1.6**	**$0.7**	$1.5	$1.0
Interest on accrued benefits	**5.3**	**2.3**	5.6	2.7
Less: actual return on plan assets	**(3.9)**	**-**	(10.4)	-
Actuarial losses (gains) on accrued benefit obligation	**(2.3)**	**(2.2)**	14.2	(4.8)
Future benefit costs before adjustments	**$0.7**	**$0.8**	$10.9	$(1.1)
Adjustments to recognize long-term nature of costs:				
Difference between expected return on assets and actual return	**(0.8)**	**-**	5.3	-
Amortization of transitional obligation	**-**	**0.7**	-	0.7
Amortization of special termination charge	**-**	**-**	0.2	0.2
Difference between amortization of actuarial losses (gains) and actual actuarial losses (gains) on accrued benefit obligations	***3.1***	***3.0***	(13.4)	5.6
Difference between amortization of past service costs and past service costs for the year	***1.0***	**-**	1.2	-
Total benefits expense	***$4.0***	***$4.5***	$4.2	$5.4

ACCRUED PENSION AND NON-PENSION BENEFIT LIABILITY

	2004		2003	
millions of dollars	Defined-benefit pension plans	Non-pension benefits plans	Defined-benefit pension plans	Non-pension benefits plans
Assumptions (weighted average)				
Accrued benefit obligation – December 31:				
Discount rate	6.00%	6.00%	6.25%	6.25%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Health care trend – initial	–	12.00%	–	9.00%
– ultimate	–	5.00%	–	5.00%
– year ultimate reached	–	2010	–	2008
Benefit cost for year ending December 31:				
Discount rate	6.25%	6.25%	6.75%	6.75%
Expected long-term return on plan assets	8.00%	8.00%	5.00%	5.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Health care trend – initial	–	12.00%	–	9.00%
– ultimate	–	5.00%	–	5.00%
– year ultimate reached	–	2010	–	2008
Accrued benefit obligations				
Balance, January 1	$ 93.2	$ 37.9	$ 95.9	$ 50.4
Employer current service cost	1.6	0.7	1.5	1.0
Interest cost	5.3	2.3	5.6	2.7
Actuarial losses (gains)	(2.3)	(2.2)	14.2	(4.8)
Benefits paid	(4.9)	(2.3)	(5.4)	(2.5)
Foreign currency translation adjustment	(6.1)	(2.5)	(18.6)	(8.9)
Balance, December 31	$ 86.8	$ 33.9	$ 93.2	$ 37.9
Fair value of plan assets				
Balance, January 1	$ 51.8	$ 1.2	$ 54.4	$ 1.5
Employer contributions	4.0	2.2	2.9	2.4
Retiree medical contributions	–	–	–	0.1
Actual investment income	3.9	–	10.4	–
Benefits paid	(4.9)	(2.3)	(5.4)	(2.5)
Foreign currency translation adjustment	(3.8)	–	(10.5)	(0.3)
Balance, December 31	$ 51.0	$ 1.1	$ 51.8	$ 1.2
Plan deficit	$ (35.8)	$ (32.8)	$ (41.4)	$ (36.7)
Unamortized past service costs	2.6	–	3.8	–
Unamortized actuarial losses (gains)	24.7	3.6	28.8	7.0
Unamortized transitional obligation	–	4.8	–	5.8
Unamortized special termination charge	–	–	1.8	1.5
Accrued benefit asset (liability)	$ (8.5)	$ (24.4)	$ (7.0)	$ (22.4)

The expected return on plan assets is determined based on the market-related value of plan assets of $55.4 million at January 1, 2004 (January 1, 2003 – $74.7 million), adjusted for interest on certain cash flows during the year.

DEFINED BENEFIT PLANS ASSET ALLOCATION

percent of plan assets	2004 Employee pension plan	2003 Employee pension plan
Equity securities	60%	66%
Debt securities	39%	33%
Other	1%	1%
Total	100%	100%

The plan assets do not include any BHE or Emera securities as at December 31, 2004 and 2003.

Plans with Accrued Benefit Obligations in Excess of Assets

As at December 31, 2004, all post-retirement benefit plans have accrued pension obligations in excess of assets.

BENEFITS EXPENSE

	2004		2003	
millions of dollars	Defined-benefit pension plans	Non-pension benefits plan	Defined-benefit pension plans	Non-pension benefits plan
Defined benefit plan				
Costs arising from events during the year:				
Current service costs	$ 1.6	$ 0.7	$ 1.5	$ 1.0
Interest on accrued benefits	5.3	2.3	5.6	2.7
Less: actual return on plan assets	(3.9)	–	(10.4)	–
Actuarial losses (gains) on accrued benefit obligation	(2.3)	(2.2)	14.2	(4.8)
Future benefit costs before adjustments	$ 0.7	$ 0.8	$ 10.9	$ (1.1)
Adjustments to recognize long-term nature of costs:				
Difference between expected return on assets and actual return	(0.8)	–	5.3	–
Amortization of transitional obligation	–	0.7	–	0.7
Amortization of special termination charge	–	–	0.2	0.2
Difference between amortization of actuarial losses (gains) and actual actuarial losses (gains) on accrued benefit obligations	–	–	(13.4)	5.6
Difference between amortization of past service costs and past service costs for the year	–	–	1.2	–
Total benefits expense	$ (0.1)	$ 1.5	$ 4.2	$ 5.4
Defined contribution plan				
Employer expense	$ 0.4	–	$ 0.3	–

Sensitivity Analysis for Non-Pension 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 the following impact in 2004:

millions of dollars	Increase	Decrease
Current service cost and interest cost	$ 0.6	$ (0.5)
Accrued benefit obligation, December 31	$ 6.7	$ (5.2)

6. OPERATING LEASES

The Company has entered into operating lease agreements for office space and telecommunication services, which expire in 2010, 2011 and 2020. Future minimum annual lease payments under the leases are as follows:

millions of dollars	
2005	$ 5.4
2006	5.4
2007	5.4
2008	5.4
2009	5.4
Thereafter	8.4
	$ 35.4

For the year ended December 31, 2004 the Company recognized $5.2 million (2003 – $5.2 million) in operating, maintenance and general expense.

7. INVESTMENTS AND EQUITY EARNINGS

Investments are comprised of the following:

	2004		2003	
millions of dollars	Carrying value	Equity earnings	Carrying value	Equity earnings
Equity accounted investments				
Maritimes & Northeast Pipeline	$ 88.0	$ 6.2	$ 91.4	$ 9.6
Maine Yankee Atomic Power Company	3.1	–	4.0	–
Maine Electric Power Company Inc.	1.4	–	1.3	–
Greyhawk Natural Gas Storage	–	–	1.8	(1.0)
Intragas Energy	1.9	–	1.9	–
Total equity investments	94.4	6.2	100.4	8.6
Long-term portfolio investments	2.4	–	2.4	–
	$ 96.8	$ 6.2	$ 102.8	$ 8.6

8. INTEREST

Interest expense consists of the following:

millions of dollars	2004	2003
Interest on long-term debt	$ 110.7	$ 115.9
Interest on short-term debt	15.2	22.6
Amortization of debt financing	1.7	1.5
Foreign exchange (gains) losses	1.6	(3.9)
Defeasance earnings and other interest income	(2.4)	(2.5)
	$ 126.8	$ 133.6

9. INCOME TAXES

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

millions of dollars	2004		2003	
Earnings before taxes	$ 206.3		$ 203.7	
Income taxes, at statutory rates	78.6	38.1%	81.7	40.1%
Unrecorded future income taxes on regulated earnings	(13.7)	(6.6)	(18.4)	(9.0)
Equity earnings not subject to tax	(2.4)	(1.2)	(3.5)	(1.7)
Large corporations tax	4.4	2.1	5.6	2.7
Other	(3.8)	(1.8)	(4.1)	(2.0)
	63.1	30.6%	61.3	30.1%
Income taxes – current	72.4		66.6	
Income taxes – future	$ (9.3)		$ (5.3)	

The future income tax assets and liabilities comprise the following:

	Current portion		Long-term portion	
millions of dollars	2004	2003	2004	2003
Future income tax assets:				
Tax loss carry forwards	$ 1.1	$ 0.6	$ 33.2	$ 27.5
Property, plant and equipment	–	–	1.2	(0.4)
Other	(0.1)	–	(0.3)	(0.5)
	$ 1.0	$ 0.6	$ 34.1	$ 26.6
Future income tax liabilities:				
Property, plant and equipment			$ 80.3	$ 74.4
Deferred charges			21.0	30.2
Deferred credits			(10.7)	(10.3)
Tax loss carry forwards			(5.2)	(2.0)
Financing			(5.2)	(1.7)
Other			(0.6)	(3.0)
			$ 79.6	$ 87.6

Rate-regulated accounting:
At December 31, 2004, the unrecorded future income tax assets of NSPI are approximately $39 million (2003 – $47 million), consisting of deductible temporary differences of $103 million (2003 – $121 million).

10. NON-CONTROLLING INTEREST

Non-controlling interest consists of NSPI and Bangor Hydro preferred share dividends less a net recovery of income tax expense of $0.8 million (2003 – $1.0 million). The income tax recovery of $6.4 million in 2004 (2003 – $6.6 million) is reflected as a reduction of preferred share dividends with an offsetting increase in income tax expense.

millions of dollars	2004	2003
Preferred share dividend	$ 14.2	$ 14.2
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)	(6.6)
	$ 13.4	$ 13.2

11. EARNINGS PER SHARE

Earnings per share for 2004 are as follows:

	2004		
	Net earnings ($ millions)	Weighted average common shares (millions)	EPS ($)
Basic EPS	$ 129.8	108.6	$ 1.20
Restricted Share Units and Deferred Share Units	–	0.5	(0.01)
Series C preferred shares of NSPI	5.8	6.9	(0.02)
Series D preferred shares of NSPI	7.5	7.4	(0.01)
Diluted EPS	$ 143.1	123.4	$ 1.16

Earnings per share for 2003 (as restated) are as follows:

	2003		
	Net earnings ($ millions)	Weighted average common shares (millions)	EPS ($)
Basic EPS	$ 129.2	108.0	$ 1.20
Series C preferred shares of NSPI	5.7	7.5	(0.03)
Series D preferred shares of NSPI	7.4	8.1	(0.02)
Diluted EPS	$ 142.3	123.6	$ 1.15

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

12. ACCOUNTS RECEIVABLE SECURITIZATION

In May 2004, NSPI renewed a revolving 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, 2004 net accounts receivables sold amounted to $80 million (2003 – $50 million). This agreement is in place until 2009 with the intention that it will be renewed at that time.

13. LONG-TERM RECEIVABLE

The current portion of the long-term receivable, which arose from Emera's 2003 sale of its 8.4% interest in the offshore platforms and sub-sea field gathering lines of the Sable Offshore Energy Project to Pengrowth Corporation, is $15.0 million (2003 – $10.0 million) and has been classified in accounts receivable on the balance sheet. The remaining balance of $20.0 million (2003 – $35.0 million) is due in 2006 (2003 – $15.0 million in 2005 and $20.0 million in 2006). See note 16.

Late payments bear interest at prime plus 500 basis points. The receivable is collateralized by the assets sold.

14. DEFERRED CHARGES AND CREDITS

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

millions of dollars	2004	2003
Deferred charges:		
Regulatory assets:		
Pre-2003 income tax liability and related interest	$ 150.0	$ 148.7
Costs to terminate/restructure purchased power contracts	48.0	72.2
Maine Yankee decommissioning costs	24.8	–
Seabrook nuclear project	22.2	26.1
Deferred restructuring costs	11.0	15.6
Hydro-Quebec obligation	5.7	–
Other	10.9	12.6
	272.6	275.2
Non-regulatory assets:		
Unamortized debt financing and defeasance costs	184.0	201.3
Accrued pension and non-pension benefit asset (note 5)	48.2	36.1
Funds placed in escrow on acquisition of generating stations	48.8	–
345 KV line to New Brunswick	7.8	4.3
Retained interest in accounts receivable securitized	7.5	5.0
Other	6.4	7.0
	302.7	253.7
	$ 575.3	$ 528.9
Deferred credits:		
Regulatory liabilities:		
Deferred stranded cost revenue requirement levelizer	$ 3.7	$ 7.5
Other	0.4	1.8
	4.1	9.3
Non-regulatory liabilities:		
Accrued pension and non-pension benefit liability (note 5)	32.9	29.4
Maine Yankee decommissioning liability	24.8	–
Hydro-Quebec obligations	5.7	–
Unearned revenue	4.9	5.8
Other	8.4	10.6
	76.7	45.8
	$ 80.8	$ 55.1

Regulatory assets consist of:

Pre-2003 Income Tax Liability and Related Interest

On June 11, 2004 the Supreme Court of Canada dismissed Nova Scotia Power's appeal to allow income tax deductions NSPI had claimed between 1998 and 2002. The deductions represented approximately $129 million in income tax otherwise payable ($150 million including interest).

NSPI had previously filed income tax returns that increased the tax depreciation (capital cost allowance) available to be deducted against NSPI's future taxable income. The Canada Revenue Agency ("CRA") disallowed the deductions claimed and NSPI successfully pursued the issue through the Tax Court of Canada. When the Federal Court overturned the Tax Court's decision, NSPI appealed this decision to the Supreme Court of Canada.

NSPI deposited the amount owing with CRA in 2001 and 2003 in order to avoid incurring non-deductible interest charges in the event the appeal was unsuccessful. The UARB provided an accounting order allowing NSPI to defer this amount while the matter was before the Supreme Court and recognized that depending on the outcome, NSPI could apply to amortize this deferral.

As a result of the Supreme Court's decision, NSPI amended its 2005 rate application to provide for amortization of the tax deposit over a seven-year period starting in 2005. The hearing before the UARB to consider the 2005 rate application took place over a three-week period, which began on November 15, 2004. Subsequent to the hearing, NSPI filed a negotiated Settlement Agreement with the UARB on December 15, 2004. The Settlement Agreement proposes to resolve the issues highlighted in its rate filings of May 28, 2004 and June 23, 2004, including the proposed treatment of the tax deposit previously deferred. The Settlement proposes to extend the amortization period to approximately 17 years. The hearing on the Settlement Agreement was conducted on January 13 and 14, 2005. A decision on this matter is currently outstanding. NSPI will continue to defer this amount until the UARB decides on the matter. Amounts ultimately not approved for recovery through rates, if any, will be charged to operations at that time.

In the meantime, beginning on January 1, 2005, the UARB has agreed to allow NSPI to defer new taxes not presently in the rates until rates allowed by the UARB in the 2005 Rate Application become effective. The amount of the deferral will be determined after year-end, and the period over which the deferral will be amortized will be determined at that time.

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 rates. The annual amortization expense is approximately $20 million, and is reduced to $5 million in 2006 when amortization related to a certain contract is completed.

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 costs of decommissioning is recorded as a deferred credit. The associated regulatory asset is being recovered through rates at a rate of $5 million per year.

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. The annual amortization expense is approximately $3 million.

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 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.

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. BHE's regulator has permitted deferral of this obligation and it is being amortized to income at a rate of $1 million per year.

Funds Placed in Escrow on Acquisition of Generating Stations

Bellows Falls Power Company ("BFP"), a 50-50 joint venture between Brascan Power Inc. and Emera Inc., entered into an agreement to lease the 49 megawatt Bellows Falls hydro-electric generating facility, located on the Connecticut River in Vermont, from the Town of Rockingham, following the Town's acquisition of the facility. BFP will pay US $72 million to lease the facility for up to 74 years (Emera's share – US $36 million). The transaction is expected to close in the second quarter of 2005, pending regulatory approvals. Emera has placed its full share of the purchase price in escrow, pending completion of the transaction.

Brascan Power Inc. and Emera Inc., in a 50-50 joint venture, will acquire Bear Swamp, a 589 megawatt pumped storage hydro-electric facility in northern Massachusetts, for a total of US $92 million (Emera's share – US $46 million). Bear Swamp is located on the Deerfield River in northern Massachusetts. Also included in the acquisition is the nearby 10 MW Fife Brook run-of-river hydro facility. The transaction is conditional on approvals of regulatory agencies and is expected to close in mid-2005. Each party has paid a deposit of US $4.5 million, pending completion of the transaction.

15. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

			2004
millions of dollars	Cost	Accumulated Depreciation	Net Book Value
Generation			
Thermal	$ 1,651.8	$ 604.0	$ 1,047.8
Gas Turbines	38.3	26.1	12.2
Combustion Turbines	76.0	3.0	73.0
Hydro-electric	364.9	118.6	246.3
Wind Turbines	2.0	0.2	1.8
Transmission	664.8	287.5	377.3
Distribution	1,254.0	535.4	718.6
Other	366.3	128.7	237.6
	$ 4,418.1	$ 1,703.5	$ 2,714.6

			2003
millions of dollars	Cost	Accumulated Depreciation	Net Book Value
Generation			
Thermal	$ 1,616.1	$ 588.0	$ 1,028.1
Gas Turbines	36.2	25.7	10.5
Combustion Turbines	41.9	0.9	41.0
Hydro-electric	358.2	114.1	244.1
Wind Turbines	1.2	0.1	1.1
Transmission	665.1	273.9	391.2
Distribution	1,230.1	508.7	721.4
Other	379.0	101.3	277.7
	$ 4,327.8	$ 1,612.7	$ 2,715.1

Rate-regulated accounting:
At December 31, 2004, the Glace Bay generating station had a net book value of $17.8 million (2003 – $22.5 million). During the year NSPI amortized $6.2 million (2003 – $6.2 million) related to the plant, and capitalized $1.5 million in AFUDC (2003 – $1.7 million) to the plant value.

16. DISPOSAL OF LONG-LIVED ASSETS

On December 31, 2003 Emera sold its 8.4% interest in the offshore platforms and sub-sea field gathering lines of the Sable Offshore Energy Project (SOEP) to Pengrowth Corporation for total proceeds of $73.6 million consisting of cash proceeds of $28.6 million and a receivable of $45.0 million. The $73.6 million consists of property, plant and equipment of $70.7 million and working capital of $2.9 million. The sale price of $65.0 million as of July 1, 2003, the effective date of the transaction, was increased to $70.7 million for capital transactions from the effective date of the transaction to the closing date. A loss of $1.2 million ($0.6 million after-tax) has been recognized in OM&G expense in 2003. The loss on sale offsets profits earned from July 1, 2003, the effective date of the transaction, to the signing date of October 31, 2003.

Rate-regulated accounting:
In December 2004 Bangor Hydro sold its corporate office facilities to a third party for cash consideration of $0.9 million. A $2.5 million loss on the disposition was netted against accumulated depreciation in accordance with Bangor Hydro's regulator approved accounting policies.

17. GOODWILL

The change in goodwill is due to the following:

millions of dollars	2004	2003
Balance, beginning of year	$ 115.1	$ 137.7
Change in foreign exchange rate	(7.4)	(22.6)
Balance, end of year	$ 107.7	$ 115.1

18. ASSET RETIREMENT OBLIGATIONS

The change in asset retirement obligations is as follows:

millions of dollars	2004	2003
Balance, beginning of year	$ 65.1	$ 62.1
Accretion included in depreciation expense	0.8	1.2
Accretion deferred to regulatory asset	2.6	1.9
Change in foreign exchange rate	–	(0.1)
Balance, end of year	$ 68.5	$ 65.1

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
Steam	5.3%	$ 242.3	16 – 35 years
Hydro	5.3%	60.8	27 – 57 years
Combustion turbines	5.3%	5.1	3 – 19 years
Other	3.3% – 8.6%	1.3	1 – 16 years
		$ 309.5	

Some of the Company's transmission and distribution assets may also have 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.

Rate-regulated accounting:
Any difference between the amount approved by the regulators of Nova Scotia Power and Bangor Hydro as depreciation expense and the amount that would have been calculated under the new accounting standard is recognized as a regulatory asset.

19. SHORT-TERM DEBT

Short-term debt consists of commercial paper of $0.2 million (2003 – nil), bankers' acceptances of $30.9 million (2003 – $81.7 million), and LIBOR loans of $73.9 million (2003 – $28.8 million) issued against lines of credit. Commercial paper, bankers' acceptances and LIBOR loans bear interest at prevailing market rates, which on December 31, 2004, averaged 2.56%, 3.13% and 3.00% respectively (2003 – 2.77%, 3.35% and 1.74%). The operating line of credit consists of advances of $15.1 million (2003 – $13.5 million), which when drawn upon, bears interest at the prime rate, which on December 31, 2004, was 4.25% (2003 – 4.5%). The short-term debt in NSPI and Emera is unsecured. Also, Bangor Hydro has a revolving credit loan agreement of $25.3 million (2003 – $5.2 million) that bears interest of 3.3% (2003 – 1.9%). This revolving credit loan is secured by a First Mortgage Bond.

20. 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.

millions of dollars	Effective Average Interest Rate % 2004	2003	Years of Maturity	2004	2003
Emera					
Medium Term Notes	6.000	6.000	2006	$ 100.0	$ 100.0
Private Placement – secured by a letter of credit	6.297	6.297	2006	10.0	10.0
Bankers Acceptances	3.115	3.344	One year renewable	8.0	40.0
NSPI					
Medium Term Notes	7.114	7.135	2005 – 2097	1,100.0	1,240.0
Debentures	9.750	9.750	2019	95.0	95.0
Commercial paper	2.557	2.765	One year renewable	262.0	81.0
Bangor Hydro (issued and payable in US$)					
First Mortgage Bonds	9.742	9.742	2020 – 2022	60.2	64.6
Financing Authority of Maine	7.030	7.030	2005	23.8	49.4
Municipal Review Committee	5.000	5.000	2008	9.5	12.7
Senior unsecured note	6.090	6.090	2012	24.1	25.9
Senior unsecured notes	5.310	5.310	2018	60.2	64.6
Less: Sinking Funds				(25.5)	(27.4)
				1,727.3	1,755.8
Less: Amount due within one year				100.8	166.3
				$ 1,626.5	$ 1,589.5

An NSPI debenture of $40.0 million bearing interest at 5.20%, maturing in 2029, is redeemable at the option of the holder in 2006. If not redeemed the interest rate on the debenture increases to 6.28% until maturity. Another NSPI debenture of $40.0 million, maturing in 2026, is extendable until 2056 at the option of the holder.

Repayments of long-term debt are due as follows:

millions of dollars

Year of Maturity	2004	2003
One year renewable	$ 270.0	$ 121.0
2004	–	166.3
2005 – net of sinking funds	100.8	100.8
2006	112.8	153.0
2007	3.1	3.4
2008	121.6	122.1
2009	130.4	–
Greater than 5 years	988.6	1,089.2
	$ 1,727.3	$ 1,755.8

21. NON-CONTROLLING INTEREST

The non-controlling interest represents preferred shares that are held in Nova Scotia Power Inc. and Bangor Hydro-Electric Company.

Authorized:

Nova Scotia Power
Unlimited number of First Preferred Shares, issuable in series.
Unlimited number of Second Preferred Shares, issuable in series.

Bangor Hydro
600,000 non-participating, cumulative preferred shares, par value US $100 per share, redeemable at the option of the issuer.

Issued and Outstanding:

millions of dollars	Millions of Shares	Preferred Share Capital
January 1, 2003	10.45	$ 267.5
Bangor Hydro preferred share redemption	(0.04)	(6.7)
December 31, 2003 and 2004	10.41	$ 260.8

Nova Scotia Power

Series C First Preferred Shares
Each Series C First Preferred Share is entitled to a $1.225 per share per annum fixed cumulative preferential dividend, as and when declared by the Board of Directors, accruing from the date of issue and payable quarterly on the first day of January, April, July and October of each year. On or after April 1, 2009, NSPI may redeem for cash the Series C First Preferred Shares, in whole at any time or in part from time to time at $25.00 per share plus accrued and unpaid dividends. The Series C First Preferred Shares will be exchangeable into Emera Inc. common shares on April 1, 2009.

Series D First Preferred Shares
Each Series D First Preferred Share is entitled to a fixed cumulative cash dividend of $1.475 per share per annum, as and when declared by the Board of Directors. These dividends will accrue from the date of issue and will be payable quarterly on the fifteenth day of January, April, July, and October of each year. On or after October 15, 2015, NSPI may redeem for cash the Series D First Preferred Shares, in whole at any time, at $25 per share plus accrued and unpaid dividends. The Series D First Preferred Shares will be exchangeable into Emera Inc. common shares on October 15, 2015.

Bangor Hydro

The preferred shares issued by Bangor Hydro consist of 6,276 (2003 – 6,277) non-callable 7% preferred shares.

22. COMMON SHARES

Authorized:

Unlimited number of non-par value Common Shares.

Issued and Outstanding:

millions of dollars	Millions of Shares	Common Share Capital
January 1, 2003	107.80	$ 1,000.2
Issued for cash under purchase plans	0.36	5.7
Options exercised under senior management share option plan	0.10	1.6
Share-based compensation	–	0.9
December 31, 2003	108.26	$ 1,008.4
Issued for cash under purchase plans	0.41	7.0
Options exercised under senior management share option plan	0.20	2.8
Share-based compensation	–	1.0
December 31, 2004	**108.87**	**$ 1,019.2**

As at December 31, 2004, there were 1.1 million (2003 – 1.3 million) common shares reserved for issuance under the senior management common share option plan, and 1.4 million (2003 – 1.5 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 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 there under. 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 anytime 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 anytime 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.

	2004		2003	
	Shares under option	Weighted average exercise price	Shares under option	Weighted average exercise price
Outstanding, beginning of year	**1,480,600**	**$ 15.98**	1,287,750	$ 16.07
Granted	**649,800**	**$ 17.77**	543,200	$ 15.73
Exercised	**(190,650)**	**$ 14.17**	(103,950)	$ 14.72
Expired	**–**	**–**	(246,400)	$ 16.40
Outstanding, end of year	**1,939,750**	**$ 16.76**	1,480,600	$ 15.98
Exercisable, end of year	**689,025**	**$ 16.41**	531,825	$ 15.81

The weighted average contractual life of options outstanding at December 31, 2004 is 7.5 years (2003 – 7.5 years). The range of exercise prices for the options outstanding at December 31, 2004 is $12.38 to $19.30 (2003 – $11.25 to $19.30).

Deferred Share Units Plan and Restricted Share Units Plan

The Company has deferred share units ("DSUs") and restricted share units ("RSUs") plans.

Under the DSUs 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 DSUs plan for executive and senior management, each participant may elect to defer all or a percentage of the 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 aware (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 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 ("MRC") Committee 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 runs from January 1, 2003 through December 31, 2005. RSUs are granted at fair value on the grant date and dividends equivalents are awarded and are used to purchase additional RSUs. The RSU value varies according to the Company's common share market price.

RSUs vest at the end of the three-year cycle and will be calculated and approved by the MRC Committee 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, 2003	–	–	–
Granted	–	129,370	13,226
December 31, 2003	–	129,370	13,226
Granted	140,130	175,880	18,796
December 31, 2004	140,130	305,250	32,022

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, 2004, $5.8 million (2003 – $0.9 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:

	2004	2003
Expected dividend yield	**5.25%**	5.31%
Expected volatility	**14.3%**	15.0%
Risk-free interest rate	**4.47%**	4.84%
Expected life	**7 years**	7 years

23. 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 options and swaps, and oil and gas options and swaps.

Non-hedging derivative financial and commodity instruments are entered into and are marked-to-market at each reporting date. The net margin recognized is reflected in other revenue.

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:

millions of dollars	2004 Carrying Amount Liability (Asset)	2004 Fair Value Liability (Asset)	2003 Carrying Amount Liability (Asset)	2003 Fair Value Liability (Asset)
Long-term debt	$ 1,727.3	$ 1,970.0	$ 1,755.8	$ 1,947.8
Short-term debt	145.4	145.4	129.2	129.4
Derivative financial instruments (hedges)				
Interest rate swaps	1.1	2.8	1.5	8.0
Interest rate caps and collars	(0.1)	0.9	–	0.3
Natural gas swaps	–	1.1	–	(0.3)
Natural gas caps and collars	–	–	(3.6)	0.4
Oil swaps	–	(0.1)	–	(13.1)
Foreign exchange contracts	–	28.2	0.5	11.5
Derivative financial instruments (non-hedges)				
Energy marketing assets	(10.3)	(10.3)	(7.7)	(7.7)
Energy marketing liabilities	9.4	9.4	7.4	7.4

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 swaps contracts converting floating rate interest on $50 million short-term debt over 2005 (2003 – $135 million over 2004 and 2005) to a weighted fixed interest rate of 6.81% (2003 – 6.24%) were outstanding at December 31, 2004.

Interest rate cap contracts limiting floating rate interest on $100 million short-term debt over 2005 (2003 – nil) to a fixed interest rate of 3.45% were outstanding at December 31, 2004.

Interest rate collar contracts limiting fixed rate interest on $25 million of long-term debt maturing in 2005 (2003 – $50 million over 2004 and 2005) to a fixed rate range between 4.89% to 5.30% (2003 – 4.81% to 5.23%) were outstanding at December 31, 2004.

Commodity Prices

The Company purchased natural gas swap contracts in 2004 to limit exposure to fluctuations in natural gas prices. As at December 31, 2004, the Company had hedged approximately 70% of all natural gas purchases and sales for 2005.

The Company enters into oil swap contracts to limit exposure to fluctuations in world prices of heavy fuel oil. As at December 31, 2004, the Company has hedged approximately 50% of 2005 requirements.

The Company has non-hedging derivative financial instruments whose value is marked-to-market at each reporting date. On December 31, 2004 the Company held 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 U.S. dollars, reducing exposure to currency rate fluctuations. Forward contracts to buy U.S. $252.1 million over 2005 to 2009 (2003 – U.S. $89.5 million over 2004 and 2005) at a weighted average rate of CAD $1.3095 (2003 – CAD $1.4167) were outstanding at December 31, 2004. There were also option contracts to hedge U.S. $5.3 million in 2005 (2003 – U.S. $52.6 million in 2004) at an average rate of CAD $1.3136 in 2005 (2003 – range of CAD $1.3180 to $1.5600 in 2004) outstanding at December 31, 2004.

The Company has non-hedging financial instruments whose value is marked-to-market at each reporting date. On December 31, 2004, the Company held 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 with respect to, and deposits are requested from, many new customers. The Company also maintains provisions for potential credit losses, which are assessed on a regular basis. With respect to customers outside of the sphere of electric customers, counterparty creditworthiness is assessed through reports of credit rating agencies or other available financial information.

24. FOREIGN EXCHANGE TRANSLATION ADJUSTMENT

millions of dollars	2004	2003
Balance, beginning of year	$ (61.1)	$ 2.9
Effect of exchange rate changes	(20.9)	(64.0)
Balance, end of year	$ (82.0)	$ (61.1)

25. RELATED PARTY TRANSACTIONS

During the year, in the ordinary course of business, the Company purchased transportation capacity totalling $45.4 million (2003 – $48.0 million) from the Maritimes & Northeast Pipeline, an investment under significant influence of the Company. The amount is recognized in fuel for generation or netted against energy marketing margin in other revenue, and is measured at the exchange amount. At December 31, 2004 the amount payable to the related party is $3.2 million (2003 – $3.9 million).

26. NET CASH FLOW PROVIDED BY OPERATING ACTIVITIES

Net cash provided by operating activities, using the indirect method, is as follows:

millions of dollars	2004	2003
Operating activities		
Net earnings before non-controlling interest	$ 143.2	$ 142.4
Non-cash items	193.5	203.5
Other operating	(40.3)	(39.3)
Operating cash flow	296.4	306.6
Pre-2003 income tax assessment	–	(133.0)
Change in non-cash operating working capital	7.6	78.3
Net cash provided by operating activities	$ 304.0	$ 251.9

27. COMMITMENTS

Emera had the following significant commitments at December 31, 2004:

- The Company has a commitment to a third party, beginning in early 2004 for seven years, to outsource management of the Company's computer infrastructure at an annual cost ranging from $5.0 million to $8.1 million.
- NSPI has an annual requirement to purchase approximately 290 GWh of electricity from independent power producers over varying contract lengths ranging from nine to twenty years.
- NSPI is required to purchase approximately 61.6 million cubic feet of natural gas per day for the next six years (subject to offshore gas production), and an additional 4 million cubic feet per day, at the option of the supplier, for four years.
- NSPI has commitments to purchase approximately 65,000 mmbtu per day of transportation capacity on the Maritimes & Northeast Pipeline for the next six years, with 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 $1.1 billion of defeasance securities held in trust. The defeasance securities must provide the principal and interest streams of the related defeased debt. Approximately 69%, or $735 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 to the Lingan and Point Aconi generation stations for ten years beginning in late 2002 at an approximate cost of $15 million per year.
- Bangor Hydro has various contracts committing it to purchase annually approximately $12 million to $16 million of electricity for the period from 2005 to 2017 from independent power producers. These commitments are reduced to approximately $2.4 million from 2018 to 2023.
- Emera Energy Services has entered into physical trading commitments for 2005, the fair value of which is reflected in energy marketing assets and liabilities on the balance sheet. The future sales commitments are $53.3 million and the future purchase commitments are $47.0 million.

28. GUARANTEES

Emera had the following guarantees at December 31, 2004:

- The Company has letters of credit issued against its operating facility totalling $27.2 million (2003 – $21.6 million). Emera's outstanding letter of credit is to secure a private placement borrowing that matures in 2006. Nova Scotia Power's letters of credit extend to 2005 or are renewed annually and secure payments to various vendors.

29. COMPARATIVE INFORMATION

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted for 2004.

Operating Statistics

FIVE-YEAR SUMMARY

Year Ended December 31	2004	2003	2002	2001	2000
Electric energy sales (GWh)					
Residential	4,632.4	4,391.1	4,401.6	3,901.7	3,632.1
Commercial	3,567.4	3,586.1	3,401.8	2,862.3	2,661.9
Industrial	4,556.1	4,449.8	4,225.9	3,952.5	3,917.2
Other	819.1	1,375.4	1,641.8	654.1	445.0
Total electric energy sales	13,575.0	13,802.4	13,671.1	11,370.6	10,656.2
Sources of energy (GWh)					
Thermal – coal	9,490.2	9,218.7	8,861.6	8,854.8	8,863.7
– oil	1,699.3	1,537.2	289.2	690.8	1,347.8
– natural gas	97.0	119.5	1,578.7	1,129.1	43.8
Hydro	983.5	1,176.8	1,108.7	692.2	881.2
Wind	2.4	2.6	0.3	–	–
Purchases	2,339.9	2,724.5	2,765.9	776.6	295.2
Total generation and purchases	14,612.3	14,779.3	14,604.4	12,143.5	11,431.7
Losses and internal use	1,037.3	976.9	933.3	772.9	775.5
Total electric energy sold	13,575.0	13,802.4	13,671.1	11,370.6	10,656.2
Electric customers					
Residential	515,726	509,824	501,233	492,256	400,653
Commercial	49,353	48,846	47,914	46,974	32,186
Industrial	2,455	2,393	2,325	2,292	2,194
Other	8,684	8,341	11,663	10,932	7,073
Total electric customers	576,218	569,404	563,135	552,454	442,106
Capacity					
Generating nameplate capacity (MW)					
Coal Fired	1,243	1,243	1,243	1,243	1,243
Dual Fired	350	350	350	350	250
Heavy Fuel Oil-Fired	–	–	–	–	100
Gas Turbine	319	274	225	225	204
Hydro-electric	395	395	395	395	395
Wind Turbine	1	1	1	–	–
Independent power producers	66	67	66	66	25
	2,374	2,330	2,280	2,279	2,217
Total number of employees	2,249	2,359	2,476	2,666	2,134
km of transmission lines	6,100	6,100	6,100	6,100	5,300
km of distribution lines	32,000	32,000	32,000	32,000	24,000

FIVE-YEAR SUMMARY

Year Ended December 31, millions of dollars	2004	2003	2002	2001	2000
Statements of Earnings Information					
Revenue	$ 1,222.0	$ 1,231.3	$ 1,227.2	$ 1,003.9	$ 896.5
Cost of operations					
Fuel for generation and power purchased	350.0	363.3	453.2	341.6	273.9
Cost of fuel oil sold	75.0	71.5	57.3	60.5	67.7
Operating, maintenance and general	254.6	269.4	284.2	194.7	168.0
Grants in lieu of property taxes	37.7	33.1	22.8	13.2	11.0
Provincial capital tax	8.6	7.8	7.3	7.6	7.2
Depreciation	132.0	127.7	127.8	108.4	98.3
	857.9	872.8	952.6	726.0	626.1
Earnings from operations	364.1	358.5	274.6	277.9	270.4
Regulatory amortization	(26.1)	(18.2)	(23.9)	(9.3)	(19.0)
Allowance for funds used during construction	4.0	5.1	4.9	5.5	4.8
Equity earnings	6.2	8.6	7.0	9.6	6.0
Earnings before interest and income taxes	348.2	354.0	262.6	283.7	262.2
Interest	126.8	133.6	144.0	122.7	115.6
Amortization of defeasance costs	15.1	16.7	19.4	19.8	19.8
Earnings before income taxes	206.3	203.7	99.2	141.2	126.8
Income tax	63.1	61.3	5.0	14.8	12.5
Net earnings before non-controlling interest	143.2	142.4	94.2	126.4	114.3
Non-controlling interest	13.4	13.2	10.6	12.2	9.9
Net earnings applicable to common shares	129.8	129.2	83.6	114.2	104.4
Common dividends	95.5	92.8	84.4	81.0	73.2
Earnings retained for use in Company	$ 34.3	$ 36.4	$ (0.8)	$ 33.2	$ 31.2
Cost of fuel for generation – coal	$ 209.1	$ 211.9	$ 229.6	$ 202.9	$ 186.3
– oil	91.1	90.4	20.6	40.3	60.5
– natural gas	(30.6)	(58.4)	62.5	35.4	5.9
Power purchased	80.4	119.4	140.5	63.0	21.2
Total cost of fuel for generation and power purchased	$ 350.0	$ 363.3	$ 453.2	$ 341.6	$ 273.9
Balance Sheets Information					
Current assets	$ 329.5	$ 305.5	$ 331.7	$ 334.4	$ 196.6
Other assets	737.1	705.6	600.3	635.1	313.2
Investments	96.8	102.8	112.2	98.6	67.0
Property, plant and equipment	2,778.3	2,777.0	2,863.7	2,891.3	2,374.2
Total assets	$ 3,941.7	$ 3,890.9	$ 3,907.9	$ 3,959.4	$ 2,951.0
Current liabilities	$ 488.7	$ 520.2	$ 697.6	$ 938.9	$ 541.3
Other liabilities	228.9	207.8	193.0	190.2	28.0
Long-term debt	1,626.5	1,589.5	1,417.8	1,381.4	1,155.0
Non-controlling interest	260.8	260.8	267.5	267.5	249.1
Common shares	1,019.2	1,008.4	1,000.2	845.4	680.8
Foreign currency translation adjustment	(82.0)	(61.1)	2.9	6.0	–
Retained earnings	399.6	365.3	328.9	330.0	296.8
Total equity and liabilities	$ 3,941.7	$ 3,890.9	$ 3,907.9	$ 3,959.4	$ 2,951.0
Statements of Cash flow information					
Cash provided by operating activities	$ 304.0	$ 251.9	$ 272.4	$ 157.3	$ 218.0
Cash used in investing activities	$ 213.9	$ 85.2	$ 109.6	$ 566.2	$ 126.1
Financial ratios ($ per common share)					
Earnings per common share	$ 1.20	$ 1.20	$ 0.85	$ 1.20	$ 1.20

board of directors and committees

BOARD OF DIRECTORS

Derek Oland (Chair)
Chairman and Chief Executive Officer,
Moosehead Breweries Limited
New River Beach, New Brunswick

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

David McD. Mann, Q.C. (retiring in May 2005)
Vice Chair, Emera Inc. and Nova Scotia Power Inc.
Halifax, Nova Scotia

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

George A. Caines, Q.C.
Stewart McKelvey Stirling Scales
Halifax, Nova Scotia

Dr. Gail Cook-Bennett (appointed in November 2004)
Chair, Canada Pension Plan Investment Board
Toronto, Ontario

Purdy Crawford, O.C. (retired in November 2004)
Counsel, Osler, Hoskin & Harcourt LLP
Chair, Allstream Inc.
Toronto, Ontario

R. Irene d'Entremont, C.M.
President, M.I.T. Electronics Inc. and
ITG Information Management Inc.
Yarmouth, Nova Scotia

James K. Gray, O.C.
Company Director,
Founder and Former Chairman,
Canadian Hunter Exploration Ltd.
Calgary, Alberta

M. Edward MacNeil
Company Director
Sydney, Nova Scotia

John T. McLennan (appointed in April 2005)
Former Vice Chair and Chief Executive Officer,
Allstream Inc.
Company Director
Mahone Bay, Nova Scotia

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

Kenneth C. Rowe
Chairman and Chief Executive Officer,
IMP Group International Inc.
Halifax, Nova Scotia

Rosemary Scanlon (retiring in May 2005)
Associate Professor of Economics,
New York University and Economics Consultant
New York, New York

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

COMMITTEES

Audit

George A. Caines (Chair)
Robert S. Briggs
Kenneth C. Rowe

Environment, Safety and Security

R. Irene d'Entremont (Chair)
James K. Gray
M. Edward MacNeil

Management Resources and Compensation

Dr. Elizabeth Parr-Johnston (Chair)
R. Irene d'Entremont
James K. Gray
Purdy Crawford, O.C. (retired in November 2004)

Nominating and Corporate Governance

Paul D. Sobey (Chair)
Dr. Gail Cook-Bennett
Rosemary Scanlon

shareholder information

Dividend Payments in 2005

Subject to Approval by the Board of Directors, common share dividends for Emera Inc. are payable on or about the 15th of February, May, August and November. A first quarter dividend of $0.2225 has been declared payable February 15, 2005.

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 3, July 27 and November 4, 2005. Year-end results for 2005 will be released in February 2006.

Annual General Meeting

The Annual General Meeting is scheduled to be held May 3, 2005 at 2:00 p.m. (Atlantic Time) at the World Trade and Convention Centre in Halifax, Nova Scotia.

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Financial Analysts, Portfolio Managers and Institutional Investors
Director, Investor and External Relations
Judy A. Steele, CA
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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: 108,865,616 million
(as at December 31, 2004)

Dividends Paid in 2004
$0.88 per Common Share

Design and Coordination: Ove Design & Communications Ltd.   www.ovedesign.com

Emera

www.emera.com