EMERA INCORPORATED

Consolidated
Financial Statements

December 31, 2012 and 2011

MANAGEMENT REPORT

Management's Responsibility for Financial Reporting

The accompanying consolidated financial statements of Emera Incorporated 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 United States Generally Accepted Accounting Principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. 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 represents 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 Incorporated 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 Incorporated'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 Incorporated. The Audit Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the consolidated financial statements and the external auditors' report. The Audit Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian Generally Accepted Auditing Standards. Ernst & Young LLP has full and free access to the Audit Committee.

February 8, 2013

"Christopher Huskilson"
President and Chief Executive Officer

"Scott Balfour"
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Emera Incorporated
We have audited the accompanying consolidated financial statements of Emera Incorporated, which comprise the consolidated balance sheets as at December 31, 2012 and 2011, and the consolidated statements of income, cash flows, comprehensive income and changes in shareholders' equity, for each of the years in the two-year period ended December 31, 2012, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Emera Incorporated as at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2012 in accordance with United States generally accepted accounting principles.

Halifax, Canada
February 8, 2013

"Ernst & Young LLP"
Chartered accountants

Emera Incorporated
Consolidated Statements of Income

For the millions of Canadian dollars (except per share amounts)	Year ended December 31 2012	2011
Operating revenues		
Regulated	**$ 1,912.7**	$ 1,891.0
Non-regulated	**145.9**	173.4
Total operating revenues	**2,058.6**	2,064.4
Operating expenses		
Regulated fuel for generation and purchased power	**810.5**	866.4
Regulated fuel and fixed cost adjustments (note 5)	**10.0**	(8.5)
Non-regulated fuel for generation and purchased power	**44.5**	73.9
Non-regulated direct costs	**56.6**	60.9
Operating, maintenance and general	**462.9**	453.3
Provincial, state, and municipal taxes	**49.4**	49.2
Depreciation and amortization	**278.2**	251.7
Total operating expenses	**1,712.1**	1,746.9
Income from operations	**346.5**	317.5
Income from equity investments (note 6)	**17.5**	34.3
Other income (expenses), net (note 7)	**36.3**	43.1
Interest expense, net (note 8)	**167.1**	159.4
Income before provision for income taxes	**233.2**	235.5
Income tax expense (recovery) (note 9)	**(12.4)**	(23.9)
Net income	**245.6**	259.4
Non-controlling interest in subsidiaries	**13.7**	11.7
Net income of Emera Incorporated	**231.9**	247.7
Preferred stock dividends	**11.1**	6.6
Net income attributable to common shareholders	**$ 220.8**	$ 241.1
Weighted average shares of common stock outstanding (in millions)		
Basic	**124.9**	121.0
Diluted	**125.3**	126.2
Earnings per common share (note 10)		
Basic	**$ 1.77**	$ 1.99
Diluted	**$ 1.76**	$ 1.97
Dividends per common share declared	**$ 1.3625**	$ 1.3125

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Consolidated Statements of Comprehensive Income

For the millions of Canadian dollars	Year ended December 31 **2012**	 2011
Net income	**$ 245.6**	$ 259.4
Other comprehensive income (loss), net of tax		
Unrealized gains (losses) on cash flow hedges (1)	**(1.6)**	(10.8)
Hedging losses (gains) included in income (2)	**4.2**	2.1
Hedging gains (losses) recognized in property, plant and equipment (3)	**0.6**	-
Net change in unrecognized pension and post-retirement benefit obligation (4)	**(86.7)**	(122.9)
Unrealized gain (loss) on available-for-sale investment (5)	**13.6**	(0.3)
Unrealized gain (loss) on translation of self-sustaining foreign operations (6)	**(34.2)**	24.4
Other comprehensive income (loss) (7) (note 11)	**(104.1)**	(107.5)
Comprehensive income (loss)	**141.5**	151.9
Less: Comprehensive income (loss) attributable to non-controlling interest	**12.2**	11.7
Preferred stock dividends	**11.1**	6.6
Comprehensive income (loss) attributable to common shareholders	**$ 118.2**	$ 133.6

The accompanying notes are an integral part of these consolidated financial statements.

1) Net of tax recovery of $2.8 million (2011 - $7.8 million tax recovery) for the year ended December 31, 2012.
2) Net of tax expense of $4.6 million (2011 - $3.2 million tax expense) for the year ended December 31, 2012.
3) Net of tax expense of $0.1 million (2011 - nil tax expense) for the year ended December 31, 2012.
4) Net of tax recovery of $2.2 million (2011 - $8.4 million tax recovery) for the year ended December 31, 2012.
5) Net of tax expense of $2.5 million (2011 - nil tax expense) for the year ended December 31, 2012.
6) Net of tax recovery of $0.4 (2011 - $0.1 million tax expense) for the year ended December 31, 2012.
7) Net of tax expense of $1.8 million (2011 - $12.9 million tax recovery) for the year ended December 31, 2012.

Emera Incorporated
Consolidated Balance Sheets

As at millions of Canadian dollars		December 31 2012		December 31 2011
Assets				
Current assets				
Cash and cash equivalents	**$**	**77.5**	$	76.9
Restricted cash (note 12)		**17.1**		14.0
Receivables, net (note 13)		**449.4**		459.6
Income taxes receivable		**54.9**		41.6
Inventory (note 14)		**177.6**		198.8
Deferred income taxes (note 9)		**14.9**		14.0
Derivative instruments (notes 15 and 16)		**24.1**		27.3
Regulatory assets (note 17)		**97.7**		141.6
Prepaid expenses		**13.3**		15.1
Other current assets		**4.5**		4.4
Total current assets		**931.0**		993.3
Property, plant and equipment, net of accumulated depreciation of $2,952.1 and $2,838.0, respectively (note 18)		**4,491.1**		4,294.4
Other assets				
Deferred income taxes (note 9)		**28.9**		33.1
Derivative instruments (notes 15 and 16)		**23.4**		39.6
Regulatory assets (note 17)		**376.4**		312.2
Net investment in direct financing lease (note 19)		**490.0**		492.0
Investments subject to significant influence (note 6)		**536.6**		219.8
Available-for-sale investments (note 20)		**141.8**		54.6
Goodwill (note 21)		**193.5**		197.7
Intangibles, net of accumulated amortization of $67.2 and $59.7, respectively		**114.2**		100.7
Due from related parties (note 22)		**151.7**		2.8
Other		**48.6**		183.4
Total other assets		**2,105.1**		1,635.9
Total assets	**$**	**7,527.2**	$	6,923.6

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Consolidated Balance Sheets – Continued

As at millions of Canadian dollars		**December 31 2012**		December 31 2011
Liabilities and Equity				
Current liabilities				
Short-term debt (note 23)	**$**	**67.5**	$	210.3
Current portion of long-term debt (note 24)		**437.1**		35.7
Accounts payable		**294.8**		332.9
Income taxes payable		**2.1**		1.9
Deferred income taxes (note 9)		**3.5**		10.9
Derivative instruments (notes 15 and 16)		**35.1**		50.1
Regulatory liabilities (note 17)		**18.2**		23.9
Pension and post-retirement liabilities (note 25)		**9.8**		8.8
Other current liabilities (note 26)		**130.9**		127.2
Total current liabilities		**999.0**		801.7
Long-term liabilities				
Long-term debt (note 24)		**3,201.1**		3,273.5
Deferred income taxes (note 9)		**312.1**		228.6
Derivative instruments (notes 15 and 16)		**22.4**		38.7
Regulatory liabilities (note 17)		**92.5**		107.1
Asset retirement obligations (note 27)		**95.0**		99.9
Pension and post-retirement liabilities (note 25)		**506.4**		530.8
Other long-term liabilities		**20.9**		19.6
Total long-term liabilities		**4,250.4**		4,298.2
Commitments and contingencies (note 28)				
Equity				
Common stock, no par value, unlimited shares authorized, 130.98 million and 122.83 million shares issued and outstanding, respectively (note 29)		**1,643.7**		1,385.0
Cumulative preferred stock, Series A and C, par value $25 per share; unlimited shares authorized, 6 million and 10 million shares issued and outstanding, respectively (note 30)		**391.6**		146.7
Contributed surplus		**2.8**		3.3
Accumulated other comprehensive loss (note 11)		**(775.8)**		(671.7)
Retained earnings		**788.1**		735.9
Total Emera Incorporated equity		**2,050.4**		1,599.2
Non-controlling interest in subsidiaries (note 31)		**227.4**		224.5
Total equity		**2,277.8**		1,823.7
Total liabilities and equity	**$**	**7,527.2**	$	6,923.6

The accompanying notes are an integral part of these consolidated financial statements.

Approved on behalf of the Board of Directors

"John T. McLennan" ***"Christopher G. Huskilson***"

Chairman **President and Chief Executive Officer**

Emera Incorporated
Consolidated Statements of Cash Flows

For the millions of Canadian dollars	Year ended December 31 2012	2011
Operating activities		
Net income	**$ 245.6**	$ 259.4
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**294.4**	263.2
Income from equity investments, net of dividends	**15.2**	(2.5)
Allowance for equity funds used during construction	**(17.2)**	(13.1)
Deferred income taxes, net	**13.0**	13.2
Net change in pension and post-retirement obligations	**(101.3)**	(8.1)
Regulated fuel and fixed cost adjustment	**3.9**	(15.2)
Net change in fair value of derivative instruments	**(5.2)**	6.6
Net change in regulatory assets and liabilities	**(7.4)**	(13.4)
Other operating activities, net	**(29.8)**	(50.3)
Changes in non-cash working capital:		
Receivables, net	**10.7**	(45.0)
Income taxes receivable	**(13.4)**	(4.2)
Inventory	**20.4**	(3.9)
Prepaid expenses	**1.7**	(1.2)
Other current assets	**(2.6)**	0.1
Accounts payable	**(35.0)**	2.1
Income taxes payable	**0.2**	1.5
Other current liabilities	**4.4**	10.3
Net cash provided by operating activities	**397.6**	399.5
Investing activities		
Additions to property, plant and equipment	**(433.6)**	(472.1)
Acquisition, net of cash acquired	**-**	(41.9)
Decrease in restricted cash	**(3.3)**	57.9
Net purchase of investments subject to significant influence, inclusive of acquisition costs (note 6)	**(173.0)**	(33.8)
Allowance for borrowed funds used during construction	**(12.5)**	(10.9)
Retirement spending, net of salvage	**(10.4)**	(16.8)
Purchase of subscription receipts	**(105.0)**	(136.0)
Loan to related party	**(152.9)**	-
Other investing activities	**(28.7)**	(7.2)
Net cash used in investing activities	**(919.4)**	(660.8)
Financing activities		
Change in short-term debt, net	**(105.7)**	133.0
Retirement of long-term debt	**(30.3)**	(13.4)
Proceeds from long term-debt	**384.9**	251.8
Net repayments under committed credit facilities	**(15.1)**	(119.6)
Issuance of common stock, net of issuance costs	**257.6**	244.0
Issuance of preferred stock, net of issuance costs	**242.7**	-
Dividends on common stock	**(168.4)**	(157.6)
Dividends on preferred stock	**(11.1)**	(6.6)
Dividends paid by subsidiaries to non-controlling interest	**(8.8)**	(8.7)
Other financing activities	**(20.8)**	8.5
Net cash provided by financing activities	**525.0**	331.4
Effect of exchange rate changes on cash and cash equivalents	**(2.6)**	(0.5)
Net increase in cash and cash equivalents	**0.6**	69.6
Cash and cash equivalents, beginning of period	**76.9**	7.3
Cash and cash equivalents, end of period	**$ 77.5**	**$** 76.9
Cash and cash equivalents consists of:		
Cash	**$ 25.4**	**$** 59.2
Short-term investments	**52.1**	17.7
Cash and cash equivalents	**$ 77.5**	**$** 76.9
Supplemental disclosure of cash paid (received):		
Interest	**$ 180.6**	**$** 170.4
Income and capital taxes	**$ (11.7)**	**$** (33.0)

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Consolidated Statements of Changes in Equity

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Loss (“AOCL”)	Retained Earnings	Non-Controlling Interest	Total Equity
2012							
Balance, December 31, 2011	$ **1,385.0**	$ **146.7**	$ **3.3**	$ **(671.7)**	$ **735.9**	$ **224.5**	$ **1,823.7**
Net income of Emera Incorporated	**-**	**-**	**-**	**-**	**231.9**	**13.7**	**245.6**
Other comprehensive income (loss), net of tax	**-**	**-**	**-**	**(104.1)**	**-**	**(1.5)**	**(105.6)**
Cash dividends declared on preferred stock ($1.1000/share)	**-**	**-**	**-**	**-**	**(11.1)**	**-**	**(11.1)**
Cash dividends declared on common stock ($1.3625/share)	**-**	**-**	**-**	**-**	**(168.6)**	**-**	**(168.6)**
Dividends paid by subsidiaries to non-controlling interest	**-**	**-**	**-**	**-**	**-**	**(1.4)**	**(1.4)**
Issuance of preferred shares, net of issuance costs	**-**	**244.9**	**-**	**-**	**-**	**-**	**244.9**
Issuance of common stock, net of issuance costs	**193.2**	**-**	**-**	**-**	**-**	**-**	**193.2**
Common stock issued under purchase plan	**49.7**	**-**	**-**	**-**	**-**	**-**	**49.7**
Senior management stock options exercised	**15.0**	**-**	**(1.1)**	**-**	**-**	**-**	**13.9**
Stock option expense	**-**	**-**	**0.6**	**-**	**-**	**-**	**0.6**
Other stock-based compensation	**0.8**	**-**	**-**	**-**	**.**	**-**	**0.8**
Preferred dividends paid by subsidiaries to non-controlling interest	**-**	**-**	**-**	**-**	**-**	**(8.0)**	**(8.0)**
Other	**-**	**-**	**-**	**-**	**-**	**0.1**	**0.1**
Balance, December 31, 2012	$ **1,643.7**	$ **391.6**	$ **2.8**	$ **(775.8)**	$ **788.1**	$ **227.4**	$ **2,277.8**
2011							
Balance, December 31, 2010	$ 1,137.8	$ 146.7	$ 3.2	$ (564.2)	$ 653.5	$ 154.4	$ 1,531.4
Net income of Emera Incorporated	-	-	-	-	247.7	11.7	259.4
Other comprehensive income (loss), net of tax	-	-	-	(107.5)	-	-	(107.5)
Issuance of common stock, net of issuance costs	196.0	-	-	-	-	-	196.0
Additional Investment	-	-	-	-	-	67.1	67.1
Cash dividends declared on preferred stock ($1.1000/share)	-	-	-	-	(6.6)	-	(6.6)
Cash dividends declared on common stock ($1.3125/share)	-	-	-	-	(158.7)	-	(158.7)
Dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	(0.7)	(0.7)
Common stock issued under purchase plan	41.0	-	-	-	-	-	41.0
Senior management stock options exercised	8.8	-	(0.6)	-	-	-	8.2
Stock option expense	-	-	0.7	-	-	-	0.7
Other stock-based compensation	1.4	-	-	-	-	-	1.4
Preferred dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	(8.0)	(8.0)
Balance, December 31, 2011	$ 1,385.0	$ 146.7	$ 3.3	$ (671.7)	$ 735.9	$ 224.5	$ 1,823.7

The accompanying notes are an integral part of these consolidated financial statements.

Emera Incorporated
Notes to the Condensed Consolidated Financial Statements
As at December 31, 2012 and 2011

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies for both the regulated and non-regulated operations of Emera Incorporated are as follows:

A. Nature of Operations

Emera Incorporated is an energy and services company which invests in electricity generation, transmission and distribution, gas transmission and utility energy services.

Emera's primary rate-regulated subsidiaries at December 31, 2012 included the following:

- Nova Scotia Power Inc. ("NSPI"), a fully-integrated electric utility and the primary electricity supplier in Nova Scotia serving approximately 497,000 customers;
- Bangor Hydro Electric Company ("Bangor Hydro") and Maine Public Service Company ("MPS"), which together provide transmission and distribution services to approximately 156,000 customers in Maine;
- an 80.1 percent interest in Light & Power Holdings Ltd. ("LPH"), the parent of The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated utility and sole provider of electricity on the island of Barbados serving approximately 134,000 customers;
- a 50.0 percent direct and 30.4 percent indirect interest (through ICD Utilities Limited ("ICDU")) in Grand Bahama Power Company Limited ("GBPC"), a vertically-integrated utility and sole provider of electricity on Grand Bahama Island serving approximately 19,000 customers; and
- Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145 kilometer pipeline carrying re-gasified liquefied natural gas from Saint John, New Brunswick to the United States border under a 25 year firm service agreement with Repsol Energy Canada ("REC").

Emera Incorporated and its subsidiaries ("Emera" or the "Company") also own investments in other energy related companies, including:

- Emera Energy Inc. ('Emera Energy"), a physical energy business which purchases and sells natural gas and electricity and provides related energy asset management services;
- Bayside Power Limited Partnership ("Bayside Power"), a 290-megawatt ("MW") electricity generating facility in Saint John, New Brunswick ;
- Emera Utility Services Inc. and Emera Utility Services (Bahamas) Limited ("Utility Services"), two utility services contractors operating in Atlantic Canada and The Bahamas;
- Emera Newfoundland & Labrador Holdings Inc. ("ENL"), a development project focused on transmission investments related to the proposed 824-MW hydroelectric generating facility at Muskrat Falls in Labrador, scheduled to be in service in 2017;
- a 49.0 percent interest in Northeast Wind Partners II, LLC ("NWP"), a 385-MW portfolio of wind energy projects in the northeastern United States;
- a 18.5 percent investment in Algonquin Power & Utilities Corp ("APUC"), a public company traded on the Toronto Stock Exchange under the symbol "AQN";
- a 50.0 percent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 600-MW pumped storage hydroelectric facility in northern Massachusetts;
- a 12.9 percent interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400 kilometer pipeline which transports natural gas from offshore Nova Scotia to markets in Maritime Canada and the northeastern United States;
- a 15.3 percent indirect interest, through LPH, in St. Lucia Electricity Services Limited ("Lucelec"), a vertically-integrated regulated electric utility in St. Lucia;
- a 37.6 percent investment in Atlantic Hydrogen Inc. ("AHI");
- a 8.2 percent investment in Open Hydro Group Limited ("Open Hydro"); and
- other investments.

B. Basis of Presentation

These consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP"). In the opinion of management, these consolidated financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera Incorporated.

All dollar amounts are presented in Canadian dollars, unless otherwise indicated.

C. Principles of Consolidation

The consolidated financial statements of Emera Incorporated include the accounts of Emera Incorporated, its majority-owned subsidiaries, and a variable interest entity where Emera is the primary beneficiary. All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes that the elimination of these transactions would understate property, plant and equipment, operating, maintenance and general expenses, or regulated fuel for generation and purchased power.

Where Emera does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. The cost method of accounting is used for investments where Emera does not have significant influence over the operating and financial policies of the investee.

Emera's equity investment in APUC has a one quarter lag in accounting as the data is not publicly available.

D. Use of Management Estimates

The preparation of consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an on-going basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. Significant estimates are included in unbilled revenue, allowance for doubtful accounts, inventory, valuation of derivative instruments, depreciation, amortization, regulatory assets and regulatory liabilities (including the determination of the current portion), income taxes (including deferred income taxes), pension and post-retirement benefits, asset retirement obligations ("AROs"), goodwill impairment assessments, valuation of investments and contingencies. Actual results may differ significantly from these estimates.

E. Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third party regulator; are designed to recover the costs of providing the regulated products or services; and it is reasonable to assume rates are set at levels such that the costs can be charged to and collected from customers.

Regulatory assets represent incurred costs that have been deferred because it is probable that they will be recovered through future rates or tolls collected from customers. Management believes that existing regulatory assets are probable of recovery either because the Company received specific approval from the appropriate regulator, or due to regulatory precedent set for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

For regulatory assets and liabilities that are amortized, the amortization is as approved by the respective regulator.

F. 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 included in income.

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 on the assets and liabilities are deferred on the balance sheet in AOCL.

G. Revenue Recognition

Operating revenues are recognized when electricity is delivered to customers or when products are delivered and services are rendered. Revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity are recognized at rates approved by the respective regulator and recorded based on meter readings and estimates, which occur on a systematic basis throughout a month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The accuracy of the unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

The Company records the net investment in a lease under the direct finance method, which consists of the sum of the minimum lease payments and residual value net of estimated executory costs and unearned income. The difference between the gross investment and the cost of the leased item for a direct financing lease is recorded as unearned income at the inception of the lease. The unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.

Other revenues are recognized when services are performed or goods delivered.

H. Research and Development Costs

Research and development costs are expensed as incurred.

I. Stock-Based Compensation

The Company has several stock-based compensation plans: a common share option plan for senior management; an employee common share purchase plan; a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. The Company accounts for its plans in accordance with the fair value based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee's or director's requisite service period using the graded vesting method. Stock-based compensation plans recognized as liabilities are measured at fair value and re-measured at fair value at each reporting date with the change in liability recognized as expense.

J. Employee Benefits

The costs of the Company's pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in AOCL.

K. Earnings per Share

Basic earnings per share ("EPS") is determined by dividing net income attributable to common shareholders by the weighted average number of common shares and DSUs outstanding during the period. Diluted EPS is computed by dividing net income attributable to common shareholders by the weighted average number of common shares and DSUs outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include Company contributions to the senior management stock option plan and preferred shares of a subsidiary.

L. Cash and Cash Equivalents

Cash equivalents consist of highly liquid short-term investments with original maturities of three months or less at acquisition. The short-term investments of $52.1 million have an effective interest rate of 2.6 percent at December 31, 2012 (2011 – $17.7 million with an effective interest rate of 3.4 percent).

M. Receivables and Allowance for Doubtful Accounts

Customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity sales are approximately 30 days. A late payment fee may be assessed on account balances after the due date.

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit risk assessments are conducted on all new customers and deposits are requested on any high risk accounts. The Company also maintains provisions for potential credit losses, which are assessed on a regular basis.

Management estimates uncollectible accounts receivable after considering historical loss experience, current events and the characteristics of existing accounts. Provisions for losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

N. Inventory

Inventory, consisting of fuel and materials, is measured at the lower of cost or market. Fuel cost is determined using the weighted average method and material cost is determined using the average costing method. Fuel and materials are charged to inventory when purchased and then expensed or capitalized, as appropriate, using the weighted average cost method for fuel and average costing method for materials.

O. Property, Plant and Equipment

Property, plant and equipment are recorded at original cost, including allowance for funds used during construction ("AFUDC") or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units of property plant and equipment are included in "Property, plant and equipment". When units of regulated property, plant and equipment are replaced, renewed or retired, their cost plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation with no gain or loss reflected in income. Where a disposition of non-regulated property, plant and equipment occurs, gains and losses are included in income as the dispositions occur.

Normal maintenance projects are expensed as incurred. Planned major maintenance projects that do not increase the overall life of the related assets are expensed. When a cost increases the life or value of the underlying asset, the cost is capitalized.

P. Capitalization Policy

The cost of property, plant, and equipment represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, AROs and overhead attributable to the capital project. Overhead includes corporate costs such as finance, information technology and executive, along with other costs related to support functions, employee benefits, insurance, inventory, and fleet operating and maintenance. Expenditures for project development are capitalized if they are expected to have future benefit.

Q. Allowance for Funds Used During Construction

AFUDC represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment. As approved by their respective regulator, NSPI, Bangor Hydro, MPS, GBPC, and Brunswick Pipeline include an equity cost component in AFUDC in addition to a charge for borrowed funds. ENL's AFUDC rate has not yet been provided to the UARB for approval and is based upon the UARB's approved methodology of determining AFUDC that applies to NSPI. AFUDC is a non-cash item; cash is realized under the rate-making process over the service life of the related property, plant and equipment through future revenues resulting from a higher rate base and recovery of higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to "Interest expense, net", while the equity component is included in "Other income (expenses), net". AFUDC is calculated using a weighted average cost of capital, as per the method of calculation approved by the respective regulator, and is compounded semi-annually. The annual AFUDC rate consisted of the following:

		2012			2011	
	Total	**Debt Component**	**Equity Component**	Total	Debt Component	Equity Component
NSPI	**7.97%**	**4.15%**	**3.82%**	7.87%	4.06%	3.81%
Bangor Hydro	**8.80%**	**2.54%**	**6.26%**	9.00%	2.60%	6.40%
MPS	**8.89%**	**2.40%**	**6.49%**	8.89%	2.40%	6.49%
GBPC	**10.00%**	**4.32%**	**5.68%**	10.00%	4.32%	5.68%
ENL	**9.10%**	**0.00%**	**9.10%**	6.50%	3.25%	3.25%

R. Depreciation

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

The estimated useful lives, in years, for each major category of property, plant and equipment consist of the following:

Generation	15 to 100
Generation - hydro	63 to 131
Generation - wind	20
Transmission	10 to 65
Distribution	11 to 80
General plant	5 to 57

S. Intangible Assets

Intangible assets consist primarily of computer software, as well as land rights and naming rights with definite lives. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated assets are determined based on formal depreciation studies and require the appropriate regulatory approval.

The estimated useful lives, in years, for each major category of intangibles with definite lives consist of the following:

Computer software	3 to 10
Land rights	50 to 143
Naming rights	1 to 24

The estimated aggregate amortization for each of the five succeeding fiscal years is as follows:

millions of Canadian dollars	2013	2014	2015	2016	2017
Computer software	7.3	5.7	5.5	4.3	4.3
Land rights	1.2	1.2	1.2	1.2	1.2
Naming rights	0.5	0.5	0.5	0.5	0.5
	9.0	7.4	7.2	6.0	6.0

T. Asset Impairment

Goodwill and Other Intangibles
Goodwill and other intangible assets with indefinite lives are not amortized, but are subject to an annual impairment test. Emera's reporting units containing goodwill perform annual goodwill impairment tests during the fourth quarter of each year, and interim impairment tests are performed when impairment indicators are present. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value.

Long-Lived Assets
Other long-lived assets require an impairment review when, based on the qualitative assessment, there is more than 50 percent likelihood that the indefinite-lived intangible asset's fair value is less than its carry amount. Emera bases its evaluation of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements, and other external market conditions or factors.

Assets Held and Used: The carrying amount of assets held and used is considered not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value.

Assets Held for Sale: The carrying value of assets held for sale is considered not recoverable if it exceeds the fair value less the cost to sell. An impairment charge is recorded for any excess of the carrying value over the fair value less estimated costs to sell.

<u>Cost and Equity Method Investments</u>
The carrying value of investments accounted for under the cost and equity methods are assessed for impairment by comparing the fair values of these investments to their carrying values, if a fair value assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists and it is determined to be other-than-temporary, a charge is recognized equal to the amount the carrying value exceeds the investment's fair value.

<u>Financial Assets</u>
The Company assesses at each balance sheet date whether there is objective evidence that a financial asset or a group of financial assets is impaired. In the case of equity securities classified as available-for-sale, an other than temporary decline in the fair value of the security below its cost is considered as an indicator that the securities are impaired. In the case of debt securities classified as available-for-sale, a breach of contract such as default or delinquency in interest or principal payments, or evidence of significant financial difficulty of the issuer is considered an indicator of impairment. If any such evidence exists for available-for-sale financial assets, the cumulative loss, measured as the difference between the acquisition cost and the current fair value, less any impairment loss on that financial asset previously recognized in income, is removed from AOCL and recognized on the Consolidated Statements of Income.

There were no material asset impairments for the quarters ended December 31, 2012 and December 31, 2011.

U. Debt Financing Costs

The Company capitalizes the external costs of obtaining debt financing and includes them in "Other" as part of "Other assets" on the Consolidated Balance Sheets. The deferred charge is amortized over the life of the related debt on an effective interest basis and included in "Interest expense, net" on the Consolidated Statements of Income.

V. Income Taxes and Investment Tax Credits

Emera recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheet and their respective tax bases using enacted tax rates in effect for the year in which the differences are expected to reverse. Emera recognizes the effect of income tax positions only when it is more likely than not that they will be realized. If management subsequently determines that it is likely that some or all of a deferred income tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

Generally, investment tax credits are recorded as a reduction to income tax expense in the current or future periods to the extent that realization of such benefit is more likely than not. Investment tax credits earned by Bangor Hydro or MPS on regulated assets are deferred and amortized over the estimated service lives of the related properties, as required by United State tax laws and Maine regulatory practices.

Emera's rate-regulated subsidiaries recognize regulatory assets or liabilities where the deferred income taxes are expected to be recovered from or returned to customers in future rates.

Emera classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively.

W. Asset Retirement Obligation

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

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

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

X. Derivatives and Hedging Activities

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

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

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

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

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

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

Derivatives that do not meet any of the above criteria are designated as HFT derivatives and are recorded on the balance sheet at fair value, with changes normally recorded in net income of the period, unless deferred as a result of regulatory accounting. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

Emera classifies gains and losses on derivatives as a component of fuel for generation and purchased power, other expenses, inventory and property, plant and equipment, depending on the nature of the item being economically hedged. Cash flows from derivative activities are presented in the same category as the item being hedged within operating or investing activities on the Consolidated Statements of Cash Flows.

Y. Fair Value Measurement

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exception (refer to notes 15 and 16), and uses a market approach to do so. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arms-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information including the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. The Company uses a fair value hierarchy, based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the highest.

The three levels of the fair value hierarchy are defined as follows:

Level 1 Valuations - Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 Valuations - Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 Valuations - Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally-developed inputs. The primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.

- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Z. Variable Interest Entities

The Company performs ongoing analysis to assess whether it holds any variable interest entities (“VIEs”). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses or the right to receive benefits of the entity that could potentially be significant to the entity. In circumstances where Emera is not deemed the primary beneficiary, the VIE is not recorded in the Company’s consolidated financial statements.

AA. Available-for-sale Investments

Assets designated as Available-for-sale are non-derivative financial assets (equity and debt securities) intended to be held for an indefinite period of time, and may be sold in response to needs for liquidity or changes in interest rates, exchange rates or equity prices.

Regular purchases and sales of financial assets are recognized at fair value, including transaction costs, on the trade date, the date on which the Company commits to purchase or sell the asset; and subsequently carried at fair value based on current bid prices on the market. Unrealized gain and losses arising from changes in the fair value of available-for-sale assets are recognized in AOCL until the financial asset is sold, or otherwise disposed of, or until the financial investment is determined to be impaired, at which time the cumulative gain or loss will be included in income for the period.

Interest on available-for-sale debt securities is calculated using the effective interest method and is recognized on the Consolidated Statements of Income in “Other income (expenses), net”. Dividends on available-for-sale equity securities are recognized on the Consolidated Statements of Income in “Other income (expenses), net”.

BB. Derivative Positions and Cash Collateral

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in “Receivables, net” and obligations to return cash collateral are recognized in “Accounts payable”.

2. CHANGE IN ACCOUNTING POLICY

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

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

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

3. FUTURE ACCOUNTING PRONOUNCEMENTS

Technical Corrections and Improvements - ASU No. 2012-04

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

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

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

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

4. SEGMENT INFORMATION

Emera manages its reportable segments separately due to their different geographical, operating and regulatory environments. Segments are reported based on each subsidiary's contribution of revenues, net income and total assets.

As at December 31, 2012, Emera has five reportable segments, specifically:

- NSPI;
- Maine Utility Operations (Bangor Hydro and MPS);
- Caribbean Utility Operations (LPH and its wholly-own subsidiary, BLPC and GBPC);

- Pipelines (Brunswick Pipeline and M&NP); and
- Other (Emera Energy Services, Bayside Power, Utility Services, Corporate, other strategic investments, holding companies, and inter-segment eliminations).

Effective Q3, 2012, MN&P and Brunswick Pipeline have been combined into one segment referred to as "Pipelines" to better reflect how Emera manages the business. In previous periods, the Company reported Brunswick Pipeline as its own segment and M&NP was reported in the "Other" segment. Prior periods have been retrospectively restated to reflect Brunswick Pipeline and M&NP as part of the "Pipelines" segment.

millions of Canadian dollars	NSPI	Maine Utility Operations	Caribbean Utility Operations	Pipelines	Other and Eliminations	Total
For the year ended December 31, 2012						
Operating revenues from external customers (1)	$ **1,237.0**	$ **205.0**	$ **420.8**	$ **50.1**	$ **98.6**	$ **2,011.5**
Inter-segment revenues (1)	**0.2**	**-**	**-**	**-**	**46.9**	**47.1**
Total operating revenues	**1,237.2**	**205.0**	**420.8**	**50.1**	**145.5**	**2,058.6**
Allowance for funds used during construction - debt and equity	**17.5**	**6.8**	**3.7**	**-**	**1.7**	**29.7**
Regulated fuel and fixed cost adjustments	**10.0**	**-**	**-**	**-**	**-**	**10.0**
Depreciation and amortization	**212.3**	**31.3**	**30.2**	**0.2**	**4.2**	**278.2**
Interest expense	**129.3**	**15.4**	**10.8**	**-**	**39.0**	**194.5**
Interest revenue	**6.9**	**0.6**	**-**	**-**	**7.4**	**14.9**
Internally allocated interest (2)	**-**	**-**	**-**	**(30.2)**	**30.2**	**-**
Gain on acquisition	**-**	**-**	**-**	**-**	**-**	**-**
Income from equity investments	**-**	**0.2**	**1.7**	**14.0**	**1.6**	**17.5**
Income tax expense (recovery)	**(29.0)**	**19.9**	**1.5**	**5.9**	**(10.7)**	**(12.4)**
Capital expenditures	**283.8**	**68.2**	**60.2**	**(1.8)**	**81.2**	**491.6**
Net income attributable to common shareholders	**126.0**	**35.4**	**23.2**	**27.9**	**8.3**	**220.8**
As at December 31, 2012						
Total assets	**3,954.2**	**986.5**	**873.2**	**600.3**	**1,113.0**	**7,527.2**
Investments subject to significant influence	**-**	**1.3**	**26.4**	**116.6**	**392.3**	**536.6**
Goodwill	**-**	**113.9**	**75.9**	**-**	**3.7**	**193.5**
For the year ended December 31, 2011						
Operating revenues from external customers (1)	$ 1,232.5	$ 202.4	$ 406.3	$ 49.8	$ 145.9	$ 2,036.9
Inter-segment revenues (1)	0.5	-	-	-	27.0	27.5
Total operating revenues	1,233.0	202.4	406.3	49.8	172.9	2,064.4
Allowance for funds used during construction - debt and equity	16.2	6.1	1.5	-	0.2	24.0
Regulated fuel and fixed cost adjustments	(8.5)	-	-	-	-	(8.5)
Depreciation and amortization	187.2	38.2	22.6	0.1	3.6	251.7
Interest expense	122.6	14.0	9.2	-	34.7	180.5
Interest revenue	10.0	0.5	-	-	(0.3)	10.2
Internally allocated interest (2)	-	-	-	(30.2)	30.2	-
Gain on acquisition	-	-	-	-	28.2	28.2
Income from equity investments	-	-	2.8	14.4	17.1	34.3
Income tax expense (recovery)	(44.9)	22.4	0.7	6.1	(8.2)	(23.9)
Capital expenditures	307.9	91.9	69.6	0.2	25.4	495.0
Net income attributable to common shareholders	123.5	37.0	46.8	27.9	5.9	241.1
As at December 31, 2011						
Total assets	3,897.0	963.0	848.9	643.1	571.6	6,923.6
Investments subject to significant influence	-	1.2	26.7	122.1	69.8	219.8
Goodwill	-	116.4	77.5	-	3.8	197.7

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes that the elimination of these transactions would understate property, plant and equipment, operating, maintenance and general expenses, or regulated fuel for generation and purchased power. Eliminated transactions are included in determining reportable segments.
(2) Segment net income is reported on a basis that included internally allocated financing costs.

5. REGULATED FUEL AND FIXED COST ADJUSTMENTS

Regulated fuel and fixed cost adjustments consisted of the following:

For the millions of Canadian dollars		Year ended December 31 2012		2011
Regulated fuel adjustment	**$**	**54.7**	$	(8.5)
Regulated fixed cost adjustment		**(44.7)**		-
	$	**10.0**	$	(8.5)

Regulated Fuel Adjustment

The regulated fuel adjustment in "Regulated fuel and fixed costs adjustments" on the Statements of Income related to the fuel adjustment mechanism ("FAM") for NSPI includes the effect of fuel costs in both the current and two preceding years, specifically, and as detailed in the table below:

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

The regulated fuel adjustment consisted of the following:

For the millions of Canadian dollars		Year ended December 31 2012		2011
Over (Under) recovery of current period fuel costs	**$**	**(15.7)**	$	(35.1)
Recovery from (rebate to) customers of prior years' fuel costs		**65.9**		26.6
FAM audit disallowance		**4.5**		-
Regulated fuel adjustment	**$**	**54.7**	$	(8.5)

The FAM regulatory asset includes amounts recognized as a fuel adjustment and associated interest that is included in "Interest expense, net" " on the Consolidated Statements of Income.

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

The following table shows the balance sheet classification of the various components of the FAM balances as at December 31:

millions of Canadian dollars		2012		2011
Current regulatory asset	**$**	**29.1**	$	69.0
Long-term regulatory asset		**14.0**		24.7
FAM regulatory asset	**$**	**43.1**	$	93.7
Current deferred income tax liability	**$**	**(9.0)**	$	(21.4)
Long-term deferred income tax liability		**(4.4)**		(7.6)
FAM deferred income tax liability	**$**	**(13.4)**	$	(29.0)

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

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

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

In December 2011, the UARB approved NSPI's request associated with the recovery of prior period fuel costs. The recovery of these costs began January 1, 2012. The approved customer rates were set to recover $69.0 million of prior years' unrecovered fuel costs in 2012.

Regulated Fixed Cost Adjustment

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

The FCR regulatory asset includes amounts recognized as a regulated fixed cost adjustment and associated interest that is included in "Interest expense, net" on the Consolidated Statements of Income.

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

The following table shows the balance sheet classifications of the various component of the FCR balance as at December 31:

millions of Canadian dollars		**2012**
Current regulatory asset	**$**	**16.5**
Long-term regulatory asset		**30.2**
FCR regulatory asset	**$**	**46.7**
Current deferred income tax liability	**$**	**(5.1)**
Long-term deferred income tax liability		**(9.4)**
FCR deferred income tax liability	**$**	**(14.5)**

6. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

Investments subject to significant influence consisted of the following:

millions of Canadian dollars	Carrying Value As at December 31		Equity Income For the year ended December 31		Percentage of Ownership
	2012	2011	**2012**	2011	**2012**
Northeast Wind Partners	**$ 206.0**	$ -	**$ (8.5)**	$ -	49.0
APUC (1) (2)	**199.4**	43.7	**-**	2.4	18.5
M&NP (1)	**116.6**	122.1	**14.0**	14.4	12.9
Lucelec (1)	**26.4**	26.7	**1.7**	$ 2.0	15.3
AHI	**4.6**	5.9	**(1.3)**	(1.6)	37.6
Maine Electric Power Company Inc.	**1.0**	0.9	**0.2**	-	21.7
Maine Yankee Atomic Power Company (1)	**0.3**	0.3	**-**	-	12.0
LPH (3)	**-**	-	**-**	0.8	-
California Pacific Utility Ventures ("CPUV") (4)	**-**	37.6	**0.3**	3.6	-
Bear Swamp	**(17.7)**	(17.4)	**11.1**	12.7	50.0
	$ 536.6	$ 219.8	**$ 17.5**	$ 34.3	

(1) Although Emera's ownership percentage of these entities is relatively low, it does have significant influence over the operating and financial decisions of these companies through Board representation. Therefore, Emera records its investment in APUC, Maine Yankee Atomic Power Company, Lucelec and M&NP using the equity method. This is consistent with industry practice for similar investments with significant influence.
(2) As at December 31, 2012, the market price per share was $6.84 (December 31, 2011 - $6.42) which indicates a fair market value of this investment of $238.7 million (December 31, 2011- $54.7 million), as the company is a publicly traded entity.
(3) Emera gained control of LPH on January 25, 2011; the above information does not include the income or the carrying value after gaining control, at which point the investments were consolidated.
(4) Emera sold the 49.999% investment held in CPUV on December 27, 2012.

Equity investments include a $139.0 million difference between the cost and the underlying fair value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill and is therefore not subject to amortization.

7. OTHER INCOME (EXPENSES), NET

Other income (expenses), net consisted of the following:

For the millions of Canadian dollars		Year ended December 31 2012		2011
Gain on exchange of subscription receipts to common shares of APUC (1)	**$**	**26.8**	$	15.1
Gain on sale of CPUV (2)		**3.6**		-
Allowance for equity funds used during construction		**17.2**		13.1
Amortization of defeasance costs		**(11.9)**		(12.1)
Foreign exchange gains (losses)		**(0.1)**		(2.7)
Foreign exchange gains (losses) recovered through the FAM		**(1.9)**		(5.2)
Recognition of regulatory asset in GBPC		**5.6**		4.4
Other		**(3.0)**		2.3
Gain on business acquisitions (3)		**-**		28.2
	$	**36.3**	$	43.1

(1) On December 27, 2012, Emera exchanged subscription receipts related to the California Pacific sale into approximately 4.8 million shares of APUC, issued at $4.72 per share which resulted in a gain of $9.9 million (after-tax gain of $8.4 million). On July 31, 2012, Emera exchanged subscription receipts related to the Atmos transaction into approximately 7.0 million common shares of APUC, issued at $6.45 per share which resulted in a gain of $1.1 million (after-tax gain of $0.9 million). On July 13, 2012, Emera exchanged subscription receipts related to the Gamesa transaction into 2.6 million common shares of APUC, issued at $5.74 per share which resulted in a gain of $2.1 million (after-tax gain of $1.8 million). On May 14, 2012, Emera exchanged subscription receipts it acquired in 2011 related to the New Hampshire transaction into 12 million APUC common shares, issued at $5.00 per share which resulted in a gain of $13.7 million (after-tax gain of $11.6 million). On January 1, 2011, Emera exchanged subscription receipts it acquired in 2009 related to the California Pacific transaction into 8.5 million APUC common shares, issued at $3.25 per share which resulted in a gain of $15.1 million (after-tax gain of $12.8 million).

(2) On December 27, 2012, Emera sold its 49.999 percent direct ownership interest in CPUV to APUC for $38.8 million, resulting in a gain of $3.6 million (after-tax gain of $2.2 million).

(3) Emera's interest in LPH was acquired in two tranches in Q2 2010 and Q1 2011 giving rise to non-taxable gains.

8. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of Canadian dollars		Year ended December 31 2012		2011
Interest on debt (1)	**$**	**187.7**	$	174.8
Allowance for borrowed funds used during construction		**(12.5)**		(10.9)
Interest revenue		**(14.9)**		(10.2)
Other		**6.8**		5.7
	$	**167.1**	$	159.4

(1) Interest on debt includes amortization of debt financing costs, premiums and discounts.

9. INCOME TAXES

The income tax provision, for the years ended December 31, differs from that computed using the statutory rates for the following reasons:

millions of Canadian dollars		2012			2011	
Income before provision for income taxes	$	**233.2**		$	235.5	
Income taxes, at statutory rates		**72.3**	**31.0 %**		76.5	32.5 %
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities		**(79.8)**	**(34.2)%**		(60.3)	(25.6)%
Non-deductible regulatory amortization		**9.4**	**4.0 %**		5.5	2.3 %
Barbados manufacturing and investment allowances		**(3.8)**	**(1.6)%**		(3.7)	(1.6)%
Recovery of prior year income taxes		**(3.2)**	**(1.4)%**		(1.7)	(0.7)%
Change in estimate of prior years expected benefit of tax deductions		**-**	**- %**		(25.2)	(10.7)%
Non-taxable gain on business acquisition		**-**	**- %**		(9.6)	(4.1)%
Reduction in FAM regulatory asset		**-**	**- %**		(4.7)	(2.0)%
Other		**(7.3)**	**(3.1)%**		(0.7)	(0.2)%
Income tax expense (recovery)	**$**	**(12.4)**	**(5.3)%**	$	(23.9)	(10.1)%

The 2012 statutory income tax rate of 31.0 percent (2011 - 32.5 percent) represents the combined Canadian federal and Nova Scotia provincial income tax rates which are the relevant tax jurisdictions for Emera.

The following reflects the composition of taxes on income from continuing operations for the years ended December 31:

millions of Canadian dollars		2012		2011
Income tax expense (recovery) - current				
Domestic	**$**	**(22.7)**	$	(43.1)
Foreign		**(2.7)**		6.0
Income tax expense (recovery) - deferred				
Domestic		**2.9**		2.8
Foreign		**34.0**		26.6
Operating loss carry forwards		**(23.2)**		(15.9)
Change in the beginning of the year valuation allowance		**(0.7)**		(0.3)
Income tax expense (recovery)	**$**	**(12.4)**	$	(23.9)

Foreign income before taxes was $128.6 million in 2012 and $173.4 million in 2011.

The deferred income tax assets and liabilities as at December 31 consisted of the following:

millions of Canadian dollars		2012		2011
Deferred income tax assets:				
Pension and other post-retirement liabilities	**$**	**222.4**	$	230.4
Tax loss carry forwards		**95.0**		74.0
Asset retirement obligations		**43.2**		42.9
Intangibles		**28.7**		27.8
Derivative instruments		**23.6**		38.1
Other		**52.3**		32.0
Total deferred income tax assets before valuation allowance		**465.2**		445.2
Valuation allowance		**(16.0)**		(17.3)
Total deferred income tax assets after valuation allowance	**$**	**449.2**	$	427.9
Deferred income tax liabilities:				
Property, plant and equipment	**$**	**564.6**	$	469.6
Net investment in direct financing lease		**58.8**		50.3
Regulatory assets (deferral of FAM)		**13.4**		29.0
Other		**84.2**		71.4
Total deferred income tax liabilities	**$**	**721.0**	$	620.3
Consolidated Balance Sheet presentation				
Current deferred income tax assets	**$**	**14.9**	$	14.0
Long-term deferred income tax assets		**28.9**		33.1
Current deferred income tax liabilities		**(3.5)**		(10.9)
Long-term deferred income tax liabilities		**(312.1)**		(228.6)
Net deferred income tax liabilities	**$**	**(271.8)**	$	(192.4)

For regulated entities, to the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, a regulatory asset or liability is recognized. These amounts include a gross up to reflect the income tax associated with future revenues required to fund these deferred income tax liabilities, and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets.

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

The following table summarizes as at December 31, 2012 the net operating loss (“NOL”), capital loss and tax credit carryovers and the associated carryover periods, and the valuation allowances for amounts which Emera has determined that realization is uncertain:

millions of Canadian dollars		Deferred Tax Asset		Valuation Allowance		Net Deferred Tax Asset	Expiration Period
NOL	$	80.5	$	(1.4)	$	79.1	2014 - 2032
Capital loss		14.5		(13.7)		0.8	Indefinite
Tax credit		0.9		-		0.9	Indefinite

As at December 31, 2012, Emera had a gross NOL carryover of $277.2 million (2011 - $215.1 million), capital loss carryover of $66.9 million (2011 - $64.1 million), and a tax credit carry forward of $1.1 million (2011 - $0.8 million).

Considering all evidence regarding the utilization of the Company’s deferred income tax assets, it has been determined that Emera is more likely than not to realize all recorded deferred income tax assets, except for the losses noted above and unrealized capital losses on certain investments. A valuation allowance has been recorded as at December 31, 2012 related to these losses and investments.

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

millions of Canadian dollars	2012	2011
Balance, January 1	$ 12.9	$ 12.9
Increases due to tax positions related to prior year	-	0.3
Increases due to tax positions related to current year	3.5	2.5
Decreases due to settlements with taxing authorities	-	(1.1)
Decreases due to expiration of statute of limitations	(1.7)	(1.7)
Balance, December 31	$ 14.7	$ 12.9

The total amount of unrecognized tax benefits as at December 31, 2012 was $14.7 million (2011 - $12.9 million) which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $1.5 million (2011 - $1.3 million). In the next twelve months, it is reasonable that $9.1 million of unrecognized tax benefits may be recognized due to enacted legislation, statute expirations or settlement agreements with taxing authorities.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, US and non-US income and withholding taxes for which deferred taxes might otherwise be required have not been provided for on a cumulative amount of temporary differences related to investments in foreign subsidiaries of approximately $355.6 million as at December 31, 2012 (2011 - $290.6 million). It is impractical to estimate the amount of income and withholding tax that might be payable if a reversal of temporary differences occurred.

Emera files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. Emera's subsidiaries file Canadian, US, Barbados and St. Lucia income tax returns. As at December 31, 2012, the Company's tax years still open to examination by taxing authorities include 2003 and subsequent years. With few exceptions, the Company is no longer subject to examination for years prior to 2006.

10. EARNINGS PER SHARE

The following table reconciles the computation of basic and diluted earnings per share:

For the millions of Canadian dollars (except per share amounts)	Year ended December 31 2012	 2011
Numerator		
Net income attributable to common shareholders	$ 220.8	$ 241.1
Preferred stock dividends of subsidiary	-	8.0
Diluted numerator (1)	220.8	249.1
Denominator		
Weighted average shares of common stock outstanding	124.3	120.5
Weighted average deferred share units outstanding	0.6	0.5
Weighted average shares of common stock outstanding – basic	124.9	121.0
Effect of dilutive securities	-	4.2
Stock-based compensation	0.4	1.0
Weighted average shares of common stock outstanding – diluted	125.3	126.2
Earnings per common share		
Basic	$ 1.77	$ 1.99
Diluted (1)	$ 1.76	$ 1.97

(1) The calculation of diluted earnings per share for the year ended December 31, 2012 excluded the impact of $8.6 million net of tax (2011 – nil) in preferred stock dividends of a subsidiary (and 4.1 million (2011 - nil) in potential common shares) as well as 0.5 million (2011 – 0.2 million) of unexercised stock options that had an anti-dilutive effect.

11. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income are as follows:

For the millions of Canadian dollars			**2012**			Year ended December 31 2011
	Opening Balance	**Net Change**	**Ending Balance**	Opening Balance	Net Change	Ending Balance
(Losses) gains on derivatives recognized as cash flow hedges	**$ (10.9)**	**$ 2.6**	**$ (8.3)**	$ (2.2)	$ (8.7)	$ (10.9)
Net change in unrecognized pension and post-retirement benefit costs	**(517.4)**	**(86.7)**	**(604.1)**	(394.5)	(122.9)	(517.4)
Hedging gain (losses) included in property, plant and equipment	**-**	**0.6**	**0.6**	-	-	-
Unrealized(loss) gain on available-for-sale investments	**(1.5)**	**13.6**	**12.1**	(1.2)	(0.3)	(1.5)
Unrealized (loss) gain on translation of self-sustaining foreign operations	**(141.9)**	**(34.2)**	**(176.1)**	(166.3)	24.4	(141.9)
Accumulated Other Comprehensive Loss	**$ (671.7)**	**$ (104.1)**	**$ (775.8)**	$ (564.2)	$ (107.5)	$ (671.7)

12. RESTRICTED CASH

Restricted cash consisted of the following:

As at millions of Canadian dollars	**December 31 2012**	December 31 2011
Restricted cash - BLPC (1)	**$ 16.3**	$ 11.2
Restricted cash - Other	**0.8**	2.8
	$ 17.1	$ 14.0

(1) $4.5 million of this cash is held for the self-insurance fund ("SIF") at BLPC for the purpose of building an insurance fund to cover risk against damage and consequential loss to certain of BLPC's generating, transmission and distribution systems. The cash is not available for the Company to use in its operations. $11.8 million of this cash is held by The Bank of Nova Scotia; as per the secured credit agreement, to partially finance the purchase of a 19.1 percent interest in Lucelec from a wholly-owned subsidiary of Emera.

13. RECEIVABLES, NET

Receivables, net consisted of the following:

As at millions of Canadian dollars	**December 31 2012**	December 31 2011
Customer accounts receivable – billed	**$ 284.8**	$ 310.7
Customer accounts receivable – unbilled	**143.2**	133.6
Total customer accounts receivable	**428.0**	444.3
Allowance for doubtful accounts	**(9.6)**	(12.8)
Customer accounts receivable, net	**418.4**	431.5
Other	**31.0**	28.1
	$ 449.4	$ 459.6

14. INVENTORY

Inventory consisted of the following:

As at millions of Canadian dollars		**December 31** **2012**		December 31 2011
Fuel	**$**	**111.9**	$	134.6
Materials		**65.7**		64.2
	$	**177.6**	$	198.8

15. DERIVATIVE INSTRUMENTS

Derivative assets and liabilities relating to the foregoing categories consisted of the following:

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**December 31 2012**	December 31 2011	**December 31 2012**	December 31 2011
Current				
Cash flow hedges				
Power & gas swaps	**$ 0.8**	$ -	**$ 0.2**	$ 8.1
Foreign exchange forwards	**3.0**	2.7	**-**	0.5
	3.8	2.7	**0.2**	8.6
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**1.8**	5.4	**1.1**	0.1
Natural gas purchases and sales	**1.5**	0.7	**9.0**	33.5
Foreign exchange forwards	**2.6**	6.0	**8.1**	-
Physical natural gas purchases and sales	**3.9**	4.2	**-**	0.1
	9.8	16.3	**18.2**	33.7
HFT derivatives				
Power swaps and physical contracts	**1.3**	1.4	**1.0**	1.2
Natural gas swaps, futures, forwards and physical contracts	**16.4**	10.9	**22.9**	10.6
	17.7	12.3	**23.9**	11.8
Total gross current derivatives	**31.3**	31.3	**42.3**	54.1
Impact of master netting agreements with intent to settle net or simultaneously	**(7.2)**	(4.0)	**(7.2)**	(4.0)
Total current derivatives	**24.1**	27.3	**35.1**	50.1
Long-term				
Cash flow hedges				
Power swaps	**1.2**	0.2	**1.3**	12.8
Interest rate swaps	**-**	-	**6.5**	6.2
Foreign exchange forwards	**1.7**	2.8	**0.3**	0.2
	2.9	3.0	**8.1**	19.2
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	6.7	**0.6**	-
Natural gas purchases and sales	**0.3**	-	**-**	5.1
Foreign exchange forwards	**11.4**	18.2	**5.0**	7.9
Physical natural gas purchases and sales	**-**	3.7	**-**	-
	11.7	28.6	**5.6**	13.0
HFT derivatives				
Power swaps and physical contracts	**-**	0.9	**-**	0.8
Natural gas swaps, futures, forwards and physical contracts	**8.8**	6.8	**8.7**	5.4
	8.8	7.7	**8.7**	6.2
Total gross long-term derivatives	**23.4**	39.3	**22.4**	38.4
Impact of master netting agreements with intent to settle net or simultaneously	**-**	0.3	**-**	0.3
Total long-term derivatives	**23.4**	39.6	**22.4**	38.7
Total derivatives	**$ 47.5**	$ 66.9	**$ 57.5**	$ 88.8

Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Cash Flow Hedges

The Company enters into various derivatives designated as cash flow hedges. Emera enters into power swaps to limit Bear Swamp's exposure to purchased power prices. The Company also enters into foreign exchange forwards to hedge the currency risk for revenue streams and capital projects denominated in foreign currency for Brunswick Pipeline and Bayside Power, respectively. MPS entered into an interest rate swap to hedge the fluctuation in interest rates on long-term debt.

As previously noted, the effective portion of the change in fair value of these derivatives is included in AOCL, until the hedged transactions are recognized in income. The ineffective portion is recognized in income of the period. The amounts related to cash flow hedges recorded in income and AOCL consisted of the following:

For the millions of Canadian dollars			**2012**			Year ended December 31 2011
	Power and Gas Swaps	**Interest Rate Swaps**	**Foreign Exchange Forwards**	Power and Gas Swaps	Interest Rate Swaps	Foreign Exchange Forwards
Unrealized gain (loss) in Non-regulated fuel for generation and purchased power – ineffective portion	**$ -**	**$ -**	**$ -**	$ (0.4)	$ -	$ -
Realized gain (loss) in Non-regulated fuel for generation and purchased power	**(10.7)**	**-**		(7.0)	-	-
Realized gain (loss) in Operating revenue - Regulated	**-**	**-**	**-**	-	-	2.7
Realized gain (loss) in Income from equity investments	**-**	**(1.5)**	**3.6**	-	-	-
Realized gain (loss) in Other income (expenses), net	**-**	**-**	**-**	-	-	(0.3)
Total gains (losses) in Net income	**$ (10.7)**	**$ (1.5)**	**$ 3.6**	$ (7.4)	$ -	$ 2.4

As at millions of Canadian dollars			**2012**			December 31 2011
	Power and Gas Swaps	**Interest Rate Swaps**	**Foreign Exchange Forwards**	Power and Gas Swaps	Interest Rate Swaps	Foreign Exchange Forwards
Total unrealized gain (loss) in AOCL – effective portion, net of tax	**$ (7.9)**	**$ (2.8)**	**$ 2.3**	$ (11.9)	$ (3.9)	$ 4.8

The Company expects $4.2 million of unrealized losses currently in AOCL to be reclassified into net income within the next twelve months, as the underlying hedged transactions settle.

As at December 31, 2012, the company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	2013	2014	2015	2016	2017
Power swaps (megawatt hours ("MWh")) purchases	0.3	0.3	0.3	0.3	0.3
Foreign exchange forwards (EURO) purchases	-	-	2.8	-	-
Foreign exchange forwards (USD) sales	$ 53.8	$ 21.0	$ 15.0	$ 0.9	$ 0.6

In addition, the Company has interest rate swaps on long-term debt of $13.5 million until 2021 and $9.0 million until 2025.

Regulatory Deferral

As previously noted, NSPI receives approval from the UARB for regulatory deferral of gains and losses on certain derivatives documented as economic hedges, including certain physical contracts that do not qualify for the NPNS exemption.

The Company has recorded the following realized and unrealized gains (losses) with respect to derivatives receiving regulatory deferral:

	Regulatory Assets		Regulatory Liabilities	
For the year ended millions of Canadian dollars	**December 31 2012**	December 31 2011	**December 31 2012**	December 31 2011
Current				
Commodity swaps and forwards				
Coal purchases	**$ 1.1**	$ (1.0)	**$ 3.6**	$ 17.3
Natural gas purchases and sales	**(25.6)**	13.7	**0.2**	(0.4)
HFO purchases	**-**	(1.3)	**-**	1.9
Foreign exchange forwards	**(3.4)**	(1.6)	**(8.1)**	(3.9)
Physical natural gas purchases and sales	**(0.1)**	0.1	**0.3**	0.1
Long-term				
Commodity swaps and forwards				
Coal purchases	**0.6**	-	**6.8**	11.8
Natural gas purchases and sales	**(5.1)**	3.3	**(0.2)**	0.1
Foreign exchange forwards	**(6.8)**	(1.5)	**2.9**	(16.0)
Physical natural gas purchases and sales	**-**	-	**3.7**	4.4

Regulatory Impact Recognized in Net Income

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

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

Commodity Swaps and Forwards

As at December 31, 2012, the Company had the following notional volumes of commodity swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

	2013		2014	
millions	Purchases	Sales	Purchases	Sales
Coal (metric tonnes)	0.3	-	0.1	-
Natural gas (Mmbtu)	19.3	10.2	3.9	0.2

Foreign Exchange Swaps and Forwards

As at December 31, 2012, the Company had the following notional volumes of foreign exchange swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

		2013		2014		2015		2016
Fuel purchases exposure (millions of US dollars)	$	212.0	$	227.0	$	227.0	$	170.0
Weighted average rate		1.0251		1.0087		1.0083		0.9929
% of USD requirements		85%		80%		80%		60%

Held-for-Trading Derivatives

In the ordinary course of its business, Emera enters into physical contracts for the purchase and sale of natural gas; and power and natural gas swaps, forwards, and futures to economically hedge those physical contracts. These derivatives are all considered HFT.

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

For the millions of Canadian dollars	Year ended December 31 **2012**		2011
Power swaps and physical contracts in non-regulated operating revenues	**$ 1.6**	$	(5.9)
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**14.5**		19.9
Foreign exchange forwards in other income (expenses), net	**-**		(0.1)
	$ 16.1	$	13.9

As at December 31, 2012, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2013	2014	2015	2016	2017	2018
Natural gas purchases (Mmbtu)	170.2	60.1	47.8	31.3	22.8	21.8
Natural gas sales (Mmbtu)	58.7	16.4	9.4	-	-	-
Power purchases (MWh)	0.1	-	-	-	-	-
Power sales (MWh)	0.1	-	-	-	-	-

Credit Risk

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

The Company assesses the potential for credit losses on a regular basis, and where appropriate, maintains provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

As at December 31, 2012, the maximum exposure the Company has to credit risk is $433.0 million (2011 - $414.9 million) which includes accounts receivable net of collateral/deposits and assets related to derivatives.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, foreign exchange and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The total cash deposits/collateral on hand as at December 31, 2012 was $63.9 million (2011 - $111.6 million) which mitigates the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements ("ISDA"), North American Energy Standards Board agreements ("NAESB") and, or Edison Electric Institute agreements. The Company believes that entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at December 31, 2012, the Company had $70.9 million (2011 - $92.3 million) in financial assets, considered to be past due, which have been outstanding for an average 61.9 days. The fair value of these financial assets is $62.5 million (2011 - $80.0 million), the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric revenue.

Concentration Risk

The Company's concentrations of risk consisted of the following:

As at	**December 31, 2012**		December 31, 2011	
	millions of Canadian dollars	**% of total exposure**	millions of Canadian dollars	% of total exposure
Receivables, net				
Regulated utilities				
Residential	**$ 168.7**	**34%**	$ 141.5	27%
Commercial	**91.3**	**18%**	92.8	18%
Industrial	**28.2**	**6%**	34.5	7%
Other	**24.5**	**5%**	28.0	5%
	312.7	**63%**	296.8	57%
Trading group				
Credit rating of A- or above	**14.2**	**3%**	7.0	1%
Credit rating of BBB- to BBB+	**23.0**	**5%**	5.5	1%
Not rated – fully collateralized	**4.5**	**1%**	11.7	2%
Not rated	**41.8**	**8%**	27.8	5%
	83.5	**17%**	52.0	9%
Other accounts receivable	**53.2**	**11%**	110.8	21%
	449.4	**91%**	459.6	87%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**30.4**	**6%**	44.3	9%
Credit rating of BBB- to BBB+	**4.7**	**1%**	10.2	2%
Not rated	**12.4**	**2%**	12.4	2%
	47.5	**9%**	66.9	13%
	$ 496.9	**100%**	$ 526.5	100%

Cash Collateral

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in “Receivables, net” and obligations to return cash collateral are recognized in “Accounts payable”.

The Company’s cash collateral positions consisted of the following:

As at millions of Canadian dollars	**December 31 2012**	December 31 2011
Cash collateral provided to others	**$ 12.9**	$ 71.6
Cash collateral received from others	**31.4**	5.7

Collateral is posted in the normal course of business based on the Company’s creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company’s derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt to fall below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at December 31, 2012, the total fair value of these derivatives, in a liability position, is $57.5 million (December 31, 2011 – $88.8 million). If the credit ratings of the Company were reduced below investment grade the full value of the net liability position could be required to be posted as collateral for these derivatives.

16. FAIR VALUE MEASUREMENTS

The following tables set out the classification of the methodology used by the Company to fair value its derivatives:

As at				December 31, 2012
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash flow hedges				
Power and gas swaps	**$ 1.9**	**$ -**	**$ 0.1**	**2.0**
Foreign exchange forwards	**-**	**4.7**	**-**	**4.7**
	1.9	**4.7**	**0.1**	**6.7**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**1.8**	**-**	**1.8**
Natural gas purchases and sales	**0.4**	**-**	**-**	**0.4**
Foreign exchange forwards	**-**	**14.0**	**-**	**14.0**
Physical natural gas purchases and sales	**-**	**-**	**3.9**	**3.9**
	0.4	**15.8**	**3.9**	**20.1**
HFT derivatives				
Power swaps and physical contracts	**-**	**-**	**0.9**	**0.9**
Natural gas swaps, futures, forwards and physical contracts	**0.4**	**3.4**	**16.0**	**19.8**
	0.4	**3.4**	**16.9**	**20.7**
Total assets	**2.7**	**23.9**	**20.9**	**47.5**
Liabilities				
Cash flow hedges				
Power and gas swaps	**0.5**	**-**	**1.0**	**1.5**
Foreign exchange forwards	**-**	**0.3**	**-**	**0.3**
Interest rate swaps	**-**	**6.5**	**-**	**6.5**
	0.5	**6.8**	**1.0**	**8.3**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**1.7**	**-**	**1.7**
Natural gas purchases and sales	**7.6**	**-**	**-**	**7.6**
Foreign exchange forwards	**-**	**13.1**	**-**	**13.1**
Physical natural gas purchases and sales	**-**	**-**	**-**	**-**
	7.6	**14.8**	**-**	**22.4**
HFT derivatives				
Power swaps and physical contracts	**0.1**	**-**	**0.5**	**0.6**
Natural gas swaps, futures, forwards and physical contracts	**2.0**	**12.7**	**11.5**	**26.2**
	2.1	**12.7**	**12.0**	**26.8**
Total liabilities	**10.2**	**34.3**	**13.0**	**57.5**
Net assets (liabilities)	**$ (7.5)**	**$ (10.4)**	**$ 7.9**	**$ (10.0)**

As at				December 31, 2011
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Power and gas swaps	$ 0.2	$ -	$ -	$ 0.2
Foreign exchange forwards	-	5.5	-	5.5
	0.2	5.5	-	5.7
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	12.1	-	12.1
Natural gas purchases and sales	(0.4)	0.7	-	0.3
HFO purchases	-	24.2	-	24.2
Physical natural gas purchases and sales	-	-	7.9	7.9
	(0.4)	37.0	7.9	44.5
HFT derivatives				
Power swaps and physical contracts	0.3	-	1.6	1.9
Natural gas swaps, futures, forwards and physical contracts	-	10.4	4.4	14.8
	0.3	10.4	6.0	16.7
Total assets	0.1	52.9	13.9	66.9
Liabilities				
Cash flow hedges				
Power and gas swaps	$ 20.9	$ -	$ -	$ 20.9
Foreign exchange forwards	-	0.7	-	0.7
Interest rate swaps	-	6.2	-	6.2
	20.9	6.9	-	27.8
Regulatory deferral				
Commodity swaps and forwards				
Natural gas purchases and sales	38.3	-	-	38.3
Foreign exchange forwards	-	7.9	-	7.9
Physical natural gas purchases and sales	-	-	0.1	0.1
	38.3	7.9	0.1	46.3
HFT derivatives				
Power swaps and physical contracts	0.3	-	1.3	1.6
Natural gas swaps, futures, forwards and physical contracts	2.7	7.3	3.1	13.1
	3.0	7.3	4.4	14.7
Total liabilities	62.2	22.1	4.5	88.8
Net assets (liabilities)	$ (62.1)	$ 30.8	$ 9.4	$ (21.9)

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2012 was as follows:

	Regulatory Deferral	***Trading Derivatives***		
millions of Canadian dollars	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1	**$ 7.9**	**$ 1.6**	**$ 4.4**	**$ 13.9**
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	**(2.8)**	**-**	**-**	**(2.8)**
Increase (reduction) in benefit included in non-regulated fuel for generation and purchased power	**-**	**0.1**	**-**	**0.1**
Unrealized gains (losses) included in regulatory assets or liabilities	**(1.2)**	**-**	**-**	**(1.2)**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**(0.7)**	**11.6**	**10.9**
Balance, December 31, 2012	**$ 3.9**	**$ 1.0**	**$ 16.0**	**$ 20.9**

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2012 was as follows:

	Regulatory Deferral	***Trading Derivatives***		
millions of Canadian dollars	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1	**$ 0.1**	**$ 1.3**	**$ 3.1**	**$ 4.5**
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	**(1.4)**	**-**	**-**	**(1.4)**
Increase (reduction) in benefit included in non-regulated fuel for generation and purchased power	**-**	**1.0**	**-**	**1.0**
Unrealized gains (losses) included in regulatory assets or liabilities	**1.3**	**-**	**-**	**1.3**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**(0.8)**	**8.4**	**7.6**
Balance, December 31, 2012	**$ -**	**$ 1.5**	**$ 11.5**	**$ 13.0**

Emera's Enterprise Risk Management group is responsible for valuation policies, processes and the measurement of fair value within Emera. The processes and methods of measurement for third-party pricing information and illiquid markets are developed with input and using the market knowledge of the trading operations within Emera and affiliates. The significant unobservable inputs used in the fair value measurement of Emera's natural gas and power derivatives includes third-party-sourced pricing for instruments based on illiquid markets; internally developed correlation factors and basis differentials; probabilities of default; and discount rates. Internally developed correlations and basis differentials are reviewed on a quarterly basis based on statistical analysis of the spot markets in the various illiquid term markets. Where possible, Emera will also source multiple broker prices in an effort to evaluate and substantiate these unobservable inputs. Discount rates may include a risk premium for those long-term forward contracts with illiquid future price points to incorporate the inherent uncertainty of these points. Any risk premiums for long-term contracts are evaluated by observing similar industry practices and in discussion with industry peers. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement.

The following table outlines quantitative information about the significant unobservable inputs used in the fair value measurements categorized within Level 3 of the fair value hierarchy:

As at					December 31, 2012
millions of Canadian dollars	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets					
Cash flow hedges – Power and gas swaps	$ 0.1	Modeled pricing	Third-party pricing	$38.85-$51.85	$42.03
			Probability of default	0.13%-0.21%	0.14%
			Discount rate	3.73%-6.33%	4.80%
Regulatory deferral – Physical natural gas purchases and sales	3.9	Modeled pricing	Third-party pricing	$4.2- $10.32	$5.99
			Probability of default	0.08% - 1.27%	0.27%
HFT derivatives – Power swaps and physical contracts	0.5	Modeled pricing	Third-party pricing	$35.09- $72.04	$52.84
			Probability of default	0.12% - 0.13%	0.12%
			Discount rate	0.00% - 0.26%	0.06%
	0.4	Modeled pricing	Third-party pricing	$35.09 - $59.81	$40.40
			Correlation factor	1.0% - 1.0%	1.00%
			Probability of default	0.15% - 0.15%	0.15%
			Discount rate	0.00% - 0.26%	0.08%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	10.1	Modeled pricing	Third-party pricing	$3.71 - $14.1	$4.76
			Probability of default	0.08% - 1.53%	1.21%
			Discount rate	0.00% - 52.92%	13.30%
	5.9	Modeled pricing	Third-party pricing	$3.038- $13.234	$5.29
			Basis adjustment	(0.12)% - 0.47%	0.24%
			Probability of default	0.06% - 3.02%	1.46%
			Discount rate	0.00% - 2.64%	0.275%
Total assets	20.9				
Liabilities					
Cash flow hedges – Power and gas swaps	$ 1.0	Modeled pricing	Third-party pricing	$38.85-$51.85	$41.65
			Probability of default	0.13%-0.13%	0.13%
			Discount rate	3.73%-6.33%	4.63%
HFT derivatives – Power swaps and physical contracts	0.5	Modeled pricing	Third-party pricing	$35.09- $72.04	$52.76
			Own credit risk	0.13%-0.13%	0.13%
			Discount rate	0.00% - 0.26%	0.06%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	10.5	Modeled pricing	Third-party pricing	$3.789- $14.1	$6.86
			Own credit risk	0.13%-0.13%	0.13%
			Discount rate	0.00% - 2.02%	0.35%
	1.0	Modeled pricing	Third-party pricing	$3.038- $14,1	$5.89
			Basis adjustment	(0.12)% - 0.47%	0.27%
			Own credit risk	0.13% - 0.13%	0.13%
			Discount rate	0.00% - 3.63%	0.43%
Total liabilities	13.0				
Net assets (liabilities)	$ 7.9				

The financial assets and liabilities included on the Consolidated Balance Sheets that are not measured at fair value consisted of the following:

As at	**December 31, 2012**		December 31, 2011	
millions of Canadian dollars	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-term debt (including current portion)	**$ 3,638.2**	**$ 4,270.2**	$ 3,309.2	$ 3,935.0

The fair values of long-term debt instruments, classified as level 3 in the fair value hierarchy, are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturity, without considering the effect of third party credit enhancements.

All other financial assets and liabilities such as cash and cash equivalents, restricted cash, accounts receivable, short-term debt and accounts payable are carried at cost. The carrying value approximates fair value due to the short-term nature of these financial instruments.

17. REGULATORY MATTERS

NSPI

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

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's target regulated return on equity ("ROE") range for 2012 is 9.1 percent to 9.5 percent (2011 – 9.1 percent to 9.6 percent) based on an actual, average regulated common equity component of up to 40 percent of actual average regulated capitalization. NSPI has a FAM, which enables NSPI to seek recovery of fuel costs through regularly scheduled rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year. Prior to 2012, the FAM had an incentive component, whereby NSPI retains or absorbs 10 percent of the over or under recovered amount to a maximum of $5 million. In November 2011, the UARB suspended the FAM incentive component for 2012 as part of the 2012 GRA Decision. The 2013 GRA settlement agreement, approved by the UARB on December 21, 2012, continues the suspension of the FAM incentive component for 2013 and 2014.

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

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

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

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

ENL

On May 17, 2012, the province of Nova Scotia passed the Maritime Link Act, in order to enable a project specific review of the Maritime Link Project by the Nova Scotia UARB. Pursuant to the Maritime Link Act, the Province announced the Maritime Link Approval Process Regulations on October 2, 2012, setting out the approval process to be followed for the Maritime Link Project.

Maine Utilities

Both Bangor Hydro and MPS' core businesses are the transmission and distribution of electricity, with distribution operations and stranded cost recoveries regulated by the Maine Public Utilities Commission ("MPUC"). Each Company's transmission operations are regulated by the Federal Energy Regulatory Commission ("FERC"). The rates for these three elements are established in distinct regulatory proceedings.

<u>Distribution Operations</u>

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

<u>Transmission Operations</u>

Bangor Hydro
Bangor Hydro's local transmission rates are set and regulated by the FERC annually on June 1, based upon a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted transmission investments and expenses. The allowed ROE for these local transmission investments is 11.14 percent. The common equity component is based upon the prior calendar year actual average balances. On June 1, 2012, Bangor Hydro's local transmission rates increased by approximately 4 percent (2011 – decreased 10 percent).

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

On June 1, 2011, Bangor Hydro's regionally recoverable transmission investments and expenses increased by 9 percent, and on June 1, 2012, it increased by a further 18 percent.

MPS
MPS local transmission rates are set and regulated by the FERC annually on June 1, based upon a formula utilizing prior year actual transmission investments and expenses. These rates go into effect June

1 for wholesale customers and July 1 for retail customers. The current allowed ROE for transmission operations is 10.5 percent, and is based on the actual prior calendar year common equity balances. On June 1, 2012, MPS' local transmission rates increased by 9 percent for wholesale customers (2011 – increased 3 percent) and then decreased by 17 percent for wholesale customers and by 5 percent for retail customers (2011 – increased by 4 percent) on July 1, 2012.

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

<u>Stranded Cost Recoveries</u>

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

Bangor Hydro
Bangor Hydro's net regulatory assets primarily include the costs associated with the restructuring of an above-market power purchase contract and the unamortized portion on its loss on the sale of its investment in the Seabrook nuclear facility. These net regulatory assets total approximately $63.9 million as at December 31, 2012 (2011 – $65.3 million) or 7.5 percent of Bangor Hydro's net asset base (2011 – 8 percent).

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

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

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

The Barbados Light & Power Company Limited

BLPC is a vertically integrated utility and sole provider of electricity on the island of Barbados.

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

BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and providing an appropriate return to investors. BLPC's approved regulated return on rate base for 2012 and 2011 is 10 percent.

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

Grand Bahama Power Company Limited

GBPC is a vertically-integrated utility and sole provider of electricity on Grand Bahama Island. The Grand Bahama Port Authority ("GBPA") regulates the utility and has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit, and distribute electricity on the island until 2054. There is a fuel pass through mechanism and flexible tariff adjustment policy to ensure that fuel costs are recovered and a reasonable return earned. Effective July 1, 2012, GBPC's approved regulated return on rate base for 2012 is 10 percent.

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

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

Brunswick Pipeline

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Canaport™ re-gasified liquefied natural gas ("LNG") import terminal near Saint John, New Brunswick, to markets in the northeastern United States. Brunswick Pipeline entered into a 25 year firm service agreement commencing in July 2009 with Repsol Energy Canada. The pipeline is considered a Group II pipeline regulated by the National Energy Board ("NEB"). The NEB Gas Transportation Tariff is filed by Brunswick Pipeline in compliance with the requirements of the NEB Act and sets forth the terms and conditions of the transportation rendered by Brunswick Pipeline.

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because it is probable that they will be recovered through future rates or tolls collected from customers. Management believes that existing regulatory assets are probable of recovery either because the Company received specific approval from the appropriate regulator, or due to regulatory precedent set for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

Regulatory assets and liabilities consisted of the following:

As at millions of Canadian dollars		**December 31 2012**		December 31 2011
Regulatory assets				
Deferred income tax regulatory asset	**$**	**166.9**	$	94.8
Unamortized defeasance costs		**70.5**		82.4
Regulated fixed cost adjustment		**46.7**		-
Regulated fuel adjustment mechanism		**43.1**		93.7
Stranded cost revenue & purchase power reconciliation deferrals		**29.8**		5.7
Deferrals related to derivative instruments		**22.7**		48.4
Pre-2003 income tax and related interest		**14.0**		42.0
Pension and postretirement medical plan		**12.5**		9.7
Purchase power contracts		**9.5**		14.2
Smart Grid		**8.3**		7.4
Seabrook nuclear project		**8.2**		11.8
Deferral of income and capital taxes not included in Q1 2005 rates		**5.6**		7.8
Hydro-Quebec Obligation		**5.4**		5.4
Asset impairment recovery		**4.5**		4.7
Deferral of demand side management		**3.2**		5.4
Deferred leasing costs		**-**		4.4
Other		**23.2**		16.0
	$	**474.1**	$	453.8
Current	**$**	**97.7**	$	141.6
Long-term		**376.4**		312.2
Total regulatory assets	**$**	**474.1**	$	453.8
Regulatory liabilities				
Self-Insurance Fund	**$**	**66.2**	$	64.7
Deferrals related to derivative instruments		**20.9**		45.6
Deferred income tax regulatory liabilities		**22.1**		19.5
Other		**1.5**		1.2
	$	**110.7**	$	131.0
Current	**$**	**18.2**	$	23.9
Long-term		**92.5**		107.1
Total regulatory liabilities	**$**	**110.7**	$	**131.0**

Deferred Income Tax Regulatory Asset and Liability

To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, a regulatory asset or liability is recognized.

Unamortized Defeasance Costs

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities held in trust that provide the principal and interest streams to match the related defeased debt, which as at December 31, 2012, totaled $0.8 billion (2011 – $1.0 billion). The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB.

Regulated Fixed Cost Adjustment

As discussed in Note 5, the regulated fixed cost adjustment reflects the FCR as approved in the 2012 GRA Decision by the UARB for fiscal 2012.

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

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

Regulated Fuel Adjustment Mechanism

As discussed in Note 5, the UARB approved the implementation of a FAM for NSPI effective January 1, 2009.

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

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

Stranded Cost Revenue & Purchased Power Reconciliation deferral

Bangor Hydro and MPS have full recovery of stranded cost revenues and expenses, with deferral of variances between actual amounts and those used to set rates. Stranded cost rates are adjusted periodically to account for these cost deferrals.

Deferrals Related to Derivative Instruments

NSPI defers changes in fair value of derivatives that are documented as economic hedges, and for which the NPNS exception has not been taken, as a regulatory asset or liability as approved by the UARB. The gain or loss is recognized when the derivatives settle in fuel for generation and purchased power, other expenses, inventory or property, plant and equipment, depending on the nature of the item being economically hedged.

Pre-2003 Income Tax and Related Interest

NSPI has a regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers as a result of capital cost allowance deductions NSPI claimed in its corporate income tax return that were disallowed in a Supreme Court decision. NSPI applied to the UARB to include recovery of these costs in customer rates. In February 2007, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

In January 2010, NSPI reached an agreement with stakeholders on its calculation of the Company's regulated ROE. The agreement provides NSPI with flexibility in amortizing its pre-2003 income tax regulatory asset such that NSPI has flexibility in recognizing additional amortization in current periods and reducing amortization in future periods. The approval of the 2012 General Rate Decision provided continuation of this flexibility for 2012, 2013 and 2014. For the year ended December 31, 2012, NSPI recorded an additional discretionary $9.8 million (2011 - $0.1 million) of regulatory amortization expense.

As part of the FAM audit decision, the UARB disallowed $2.0 million, which was applied in 2012 against this deferral.

Pension and Postretirement Medical Plan

As a result of purchase accounting, all unrecognized actuarial gains and losses, prior service cost, and the net transition asset/liability associated with the pension and postretirement medical benefit plans were eliminated as a result of the Bangor Hydro and MPS mergers with Emera. As a result of regulatory accounting, a regulatory asset of $30 million, equal to these unrecognized amounts was established at the merger dates. Bangor Hydro and MPS are amortizing the regulatory asset balance over the same period at which the corresponding gains and losses were being amortized when they were a component of pension and postretirement benefit expense.

Power Purchase Contracts

Bangor Hydro has power purchase contracts, which it was required to negotiate when oil prices were high, with several independent power producers. Bangor Hydro attempted to alleviate the adverse impact of these high-cost contracts and in doing so incurred costs to restructure certain of the contracts. The MPUC has allowed Bangor Hydro to defer these costs and recover them in stranded cost rates. The contract restructuring costs are being recovered over a 20-year period ended in June 2018. In 2011, Bangor Hydro entered into a 20-year power purchase contract with a 60MW wind farm to purchase 20 percent of the energy generated. Also in 2011, Bangor Hydro entered into a 20-year power purchase contract with a 1 MW biomass generator to purchase 100% of the energy generated. As with the Company's other power purchase contracts, the MPUC has allowed Bangor Hydro full cost recovery for these contracts.

Smart Grid

In 2010, Bangor Hydro received an Accounting Order from the MPUC which allowed for the deferral of costs associated with Bangor Hydro's Smart Grid project for future recovery.

Seabrook Nuclear Project

Bangor Hydro and MPS were participants in the Seabrook nuclear project in Seabrook, New Hampshire. In 1986 Bangor and MPS sold their respective interests with a combined cost of approximately $179.1 million. Both companies reached separate agreements with the MPUC providing for the recovery through customer rates of, in Bangor Hydro's case, 70 percent of 1984 year-end investment in Seabrook Unit 1 over 30 years ending in October 2015 and, in MPS's case, 60 percent costs associated with Seabrook Units 1 and 2 over 30 years ending in 2016. In the last MPS stranded cost rate case, the Seabrook amortization period was revised so that the regulatory asset will be fully amortized at the end of 2014.

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

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. As a result, NSPI deferred $16.7 million, consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes. The UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

Hydro-Quebec Obligation

The obligation associated with Hydro-Quebec represents the estimated present value of Bangor Hydro's estimated future payments for net costs associated with ownership and operation of the Hydro-Quebec intertie between the New England utilities and Hydro-Quebec. The obligation has been recognized in other liabilities and the MPUC has permitted recovery of this obligation. The regulatory asset and obligation are being reduced as expenses are incurred with the reduction of the regulatory asset amortized to purchase power expense.

Asset Impairment Recovery

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

Deferral of Demand Side Management

The UARB agreed to allow NSPI to defer up to $12.8 million of demand side management expenditures for the period January 1, 2008 through December 31, 2009, to be recovered in rates over six years commencing January 1, 2009.

Deferred Leasing Costs

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

Self-Insurance Fund

LPH has established a SIF primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. LPH holds a variable interest in the SIF for which it was determined that LPH was the primary beneficiary and, accordingly, the SIF must be consolidated by LPH. In its determination that LPH controls the SIF, management considered that in substance the activities of the SIF are being conducted on behalf of LPH's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because LPH, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF. The SIF Fund assets are not available to the Company for use in its operations**.**

18. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following regulated and non-regulated assets:

As at millions of Canadian dollars		December 31 **2012**		December 31 2011
Generation	**$**	**3,347.0**	$	3,208.5
Transmission		**1,357.6**		1,027.4
Distribution		**1,731.9**		1,893.6
General plant and other		**726.6**		531.4
Total cost		**7,163.1**		6,660.9
Less: Accumulated depreciation		**(2,952.1)**		(2,838.0)
		4,211.0		3,822.9
Construction work in progress		**280.1**		471.5
Net book value	**$**	**4,491.1**	$	4,294.4

For the year ended December 31, 2012, AFUDC of $29.4 million (2011 – $23.6 million) was capitalized to "Property, plant and equipment".

As a result of regulator-approved accounting policies and depreciation rates, NSPI, Bangor Hydro, and MPS defer certain costs within "Property, plant and equipment" that would not otherwise be deferred in the absence of rate-regulation. Cumulative differences between items recognized for rate regulatory purposes and applicable accounting standards including depreciation rates, AFUDC and overhead costs cannot be separately determined. Cumulative accretion expense related to AROs were $17.1 million as at December 31, 2012 (2011 – $17.1 million).

19. NET INVESTMENT IN DIRECT FINANCING LEASE

Brunswick Pipeline commenced service on July 16, 2009, transporting re-gasified LNG for Repsol Energy Canada under a 25 year firm service agreement. The agreement meets the definition of a direct financing capital lease for accounting purposes. The net investment in direct financing lease consists of the sum of the minimum lease payments and residual value net of estimated executory costs and unearned income. The unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease. Net investment in direct financing lease consisted of the following:

As at millions of Canadian dollars		**December 31 2012**		December 31 2011
Total minimum lease payments to be received	**$**	**1,382.0**	$	1,440.7
Less: amounts representing estimated executory costs		**(240.8)**		(249.8)
Minimum lease payments receivable	**$**	**1,141.2**	$	1,190.9
Estimated residual value of leased property (unguaranteed)		**183.0**		183.0
Less: unearned finance lease income		**(832.3)**		(880.1)
Net investment in direct financing lease	**$**	**491.9**	$	493.8
Principal due within one year (included in “Other current assets”)		**1.9**		1.8
Net investment in direct financing lease – long-term	**$**	**490.0**	$	492.0

Future minimum lease payments to be received for the next five years:

For the										Year ended December 31
millions of Canadian dollars		2013		2014		2015		2016		2017
Minimum lease payments to be received	$	58.8	$	60.0	$	61.6	$	61.6	$	61.6
Less: amounts representing estimated executory costs		(9.2)		(9.4)		(9.6)		(9.8)		(9.9)
Minimum lease payments receivable	$	49.6	$	50.6	$	52.0	$	51.8	$	51.7

20. AVAILABLE-FOR-SALE INVESTMENTS

The available-for-sale investments consists of APUC subscription receipts which are readily convertible to 11.3 million common shares of APUC, subject to regulatory approval, and investments in debt and equity investments held in trust on behalf of BLPC’s SIF for the purpose of building an insurance fund to cover risk against damage and consequential loss to certain of BLPC’s generating, transmissions and distribution systems. The SIF Fund assets are not available to the Company for use in its operations.

Emera has classified these investments as available-for-sale and recorded all such investments at their fair market value as at December 31, 2012.

Available-for-sale financial assets measured at fair value include the following:

As at millions of Canadian dollars		**Level 1**	**Level 2**	**Level 3**	**December 31 2012**
Common shares	**$**	**12.3 $**	**- $**	**- $**	**12.3**
Mutual funds		**23.5**	**-**	-	**23.5**
Corporate bonds, debentures, short and medium term notes		**-**	**21.9**	-	**21.9**
Government bonds		**-**	**7.1**	-	**7.1**
Subscription receipts convertible to common shares		**-**	**77.0**	-	**77.0**
	$	**35.8 $**	**106.0 $**	**- $**	**141.8**

As at millions of Canadian dollars		Level 1	Level 2	Level 3	December 31 2011
Common shares	$	1.3 $	- $	- $	1.3
Mutual funds (1)		-	17.8	-	17.8
Corporate bonds, debentures, short and medium term notes (1)		-	27.7	-	27.7
Government bonds		7.8	-	-	7.8
	$	9.1 $	45.5 $	- $	54.6

(1) Balance was retroactively reclassified from Level 1 to Level 2 effective Q4, 2012.

The fair value of financial instruments traded in active markets is based on quoted market prices at the balance sheet date. The quoted market price used for financial assets is the current bid price at the balance sheet date.

The change in available-for-sale assets is as follows:

As at millions of Canadian dollars		**December 31 2012**	December 31 2011
Balance, beginning of the year	**$**	**54.6** $	0.8
Resulting from acquisitions		**-**	53.5
Additions, net of foreign exchange loss		**85.0**	36.5
Disposals		**(14.4)**	(35.8)
	$	**125.2** $	55.0
Change in fair value			
Gain (Loss) recognized in regulatory liability		**1.7**	(0.1)
Gain (Loss) recognized in other comprehensive income during the period		**14.9**	(0.3)
	$	**16.6** $	(0.4)
Balance, end of the period	**$**	**141.8** $	54.6

There were no impairment provisions for available-for-sale investments for the years ended December 31, 2012 and 2011.

The maturity profile of debt securities included in the available-for-for-sale assets is as follows:

As at millions of Canadian dollars		**December 31 2012**	December 31 2011
Maturity within 1 year	**$**	**12.9** $	12.7
Maturity in 1-5 years		**16.1**	22.8
	$	**29.0** $	35.5

The maximum exposure to credit risk at the reporting date is the carrying value of the debt securities. None of these financial instruments are either past due or impaired.

21. GOODWILL

The change in goodwill for the years ended December 31 is due to the following:

millions of Canadian dollars		**2012**		2011
Balance, January 1	**$**	**197.7**	$	167.4
Acquisitions		**-**		26.1
Change in foreign exchange rate		**(4.2)**		4.2
Balance, December 31	**$**	**193.5**	$	197.7

22. RELATED PARTY TRANSACTIONS

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

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

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

Following are transactions between Emera and its equity investments:

M&NP

In the ordinary course of business, Emera purchased natural gas transportation capacity from M&NP, an investment under significant influence of the Company, totaling $35.6 million (2011 – $47.3 million) for the year ended December 31, 2012. The amount is recognized in “Regulated fuel for generation and purchased power” or netted against energy marketing margin in “Non-regulated operating revenues” and is measured at the exchange amount. As at December 31, 2012, the amount payable to the related party was $2.9 million (December 31, 2011 – $3.3 million), and is under normal interest and credit terms.

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

Lucelec

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

First Wind

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

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

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

CPUV

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

23. SHORT-TERM DEBT

Emera's short-term borrowings consist of commercial paper issuances, advances on the revolving credit facilities and short-term notes. Short-term debt and related the weighted-average interest rate as at December 31 consisted of the following:

millions of Canadian dollars		**2012**	**Weighted-average interest rate**		2011	Weighted-average interest rate
Emera						
Current portion of Advances on the revolving credit facilities (1)	**$**	**-**	**- %**	$	2.4	3.50 %
Promissory note issued to APUC		**-**	**-%**		135.8	- %
NSPI						
Current portion of Advances on the revolving credit facilities (1)		**7.9**	**3.00 %**		4.6	3.25 %
Commercial paper (2)		**56.3**	**1.15 %**		59.3	1.08 %
MPS						
Advances on the revolving credit facilities		**3.3**	**1.96 %**		0.7	3.25 %
GBPC						
Advances on the revolving credit facilities		**-**	**- %**		7.5	5.75 %
Short-term debt	**$**	**67.5**		$	210.3	

(1) Advances on the long-term revolving credit facilities (Note 24) can be made by way of overdraft and prime rate borrowing on accounts for Emera and NSPI for up to $30 million and $50 million, respectively.
(2) NSPI's commercial paper is backed by a revolving credit facility which matures in 2017. NSPI has the ability to refinance commercial paper on a long-term basis; however amounts expected to be paid through working capital are classified as short-term debt. All other drawings are classified as long-term debt (Note 24).

The Company's total short-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

millions of Canadian dollars	Maturity		**2012**		2011
MPS – revolving credit facility	2013	**$**	**9.9**	$	10.2
GBPC – revolving credit facility	2013		**-**		11.2
Total			**9.9**		21.4
Less:					
Advances under revolving credit facilities			**3.3**		8.2
Use of available facilities			**3.3**		8.2
Available capacity under existing agreements		**$**	**6.6**	$	13.2

As at December 31, 2012, these credit facilities require commitment fees of 0.25%. The weighted average interest rate on outstanding short-term debt at December 31, 2012 was 1.96% (2011 – 1.78%).

Credit Facilities

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

24. LONG-TERM DEBT

Emera's long-term debt includes the issuances detailed below. Medium-term notes and debentures 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. Long-term debt as at December 31 consisted of the following:

millions of Canadian dollars	Stated Interest Rate	Effective Interest Rate	Maturity	2012	2011
EMERA					
Bankers acceptances, LIBOR loans (1)	-	1.10%	5 year renewal	**$ 302.5**	$ 251.0
Medium-term notes					
Series F	4.10%	4.19%	2014	**250.0**	250.0
Series G	4.83%	4.89%	2019	**225.0**	225.0
Series H	2.96%	3.05%	2016	**250.0**	250.0
				725.0	725.0
Promissory note	-	-	2016	**1.3**	1.8
Capital lease obligations	-	-	Various	**1.0**	1.7
				$ 1,029.8	$ 979.5
NSPI					
Commercial Paper (2)	-	1.15%	5 year renewal	**$ 291.2**	$ 312.8
Medium-term notes					
Series F	8.85%	8.21%	2025	**125.0**	125.0
Series I	8.40%	8.43%	2015	**70.0**	70.0
Series L	8.30%	8.88%	2036	**60.0**	60.0
Series M (3)	8.50%	7.76%	2026	**40.0**	40.0
Series N	7.60%	7.57%	2097	**50.0**	50.0
Series P	6.28%	6.28%	2029	**40.0**	40.0
Series R	7.45%	7.51%	2031	**75.0**	75.0
Series S	6.95%	7.12%	2033	**200.0**	200.0
Series T	5.75%	6.09%	2013	**300.0**	300.0
Series V	5.67%	5.71%	2035	**150.0**	150.0
Series W	5.95%	6.01%	2039	**200.0**	200.0
Series X	5.61%	5.65%	2040	**300.0**	300.0
Series Y	4.15%	4.19%	2042	**250.0**	-
				1,860.0	1,610.0
Debentures – Series 3	9.75%	9.99%	2019	**95.0**	95.0
				$ 2,246.2	$ 2,017.8
Bangor Hydro (4)					
LIBOR loans and demand loans (5)	-	1.71%	2013	**$ 15.4**	$ 63.3
General & refunding mortgage bonds (6)					
$20 million	8.98%	8.98%	2022	**19.9**	20.3
$30 million	10.25%	10.25%	2020	**29.8**	30.5
				49.7	50.8
Senior unsecured notes					
$20 million 2002	6.09%	6.09%	2012	**-**	20.3
$50 million 2003 (7)	5.31%	5.31%	2018	**27.1**	32.3
$30 million 2007	5.65%	5.65%	2014	**29.9**	30.5
$20 million 2007	5.87%	5.87%	2017	**19.9**	20.3
$70 million 2012	3.61%	3.61%	2022	**69.6**	-
				146.5	103.4
				$ 211.6	$ 217.5
MPS (4)					
Maine Public Utility Financing Bank Bonds (8)	0.46%	6.20%	2021	**$ 13.5**	$ 13.8
Maine Public Utility Financing Bank Bonds (8)	0.46%	6.32%	2025	**9.0**	9.2
				$ 22.5	$ 23.0

GBPC (4)							
Advances on the revolving credit facilities	-	5.75%	2014	**$**	**9.2**	$	-
Unsecured notes	3.18%	3.57%	2014		**72.8**		31.9
Bond notes	7.07%	7.07%	2020-2023		**51.0**		52.7
				$	**133.0**	$	84.6
BLPC & LPH							
Senior secured notes							
$14.2 million 2015	2.37%	2.37%	2015	**$**	**11.6**	$	-
$12.3 million 2021 (9)	6.50%	7.00%	2021		**10.3**		11.3
$9.9 million 2020 (9)	6.65%	6.65%	2020		**9.9**		10.2
$9.9 million 2025 (9)	6.88%	6.88%	2025		**9.9**		10.2
$10 million 2015 (10)	5.99%	5.99%	2015		**3.0**		4.3
$34 million 2013 (11)	4.27%	4.27%	2013		**3.9**		7.9
Other					**0.5**		-
				$	**49.1**	$	43.9
Adjustments							
Commercial Paper in NSPI (2)	1.15%	5 year renewal		**$**	**(56.3)**	$	(59.3)
Unamortized debt discount - net					**2.3**		2.2
Amount due within one year					**(437.1)**		(35.7)
				$	**(491.1)**	$	(92.8)
Long-Term Debt				**$**	**3,201.1**	$	3,273.5

(1) Emera's revolving credit facility matures in June 2017, at which point the Company has the intention to renew under similar terms. The credit facility can be extended annually with the approval of the syndicated banks.
(2) NSPI's commercial paper is backed by a revolving credit facility which matures in 2017. NSPI has the ability to refinance commercial paper on a long-term basis; however amounts expected to be paid through working capital are classified as short-term debt (Note 23). All other drawings are classified as long-term debt.
(3) Notes extendable until 2056 at the option of the holders.
(4) Debt issued and payable in USD.
(5) Bangor Hydro's revolving credit facility matures in September 2013, at which point the Company has the intention to renew under similar terms.
(6) Secured by property, plant and equipment of Bangor Hydro.
(7) Sinking fund payments beginning in year five.
(8) The interest on these USD variable rate bonds is fixed through the MPS interest rate swaps. The 1996 Series bonds of $13.6 million, due in 2021, are fixed at 4.42 percent, while the 2000 Series bonds of $9.0 million, due in 2025, are fixed at 4.53 percent.
(9) Debt issued and payable in Barbadian dollars. Borrowings are secured under a Debenture Trust Deed which creates a first and floating charge on the Company's property, present and future.
(10) Debt issued and payable in USD. Borrowings are secured under a Debenture Trust Deed which creates a first and floating charge on the Company's property, present and future.
(11) Debt issued and payable in USD. Borrowings are guaranteed by the Government of Barbados.

The Company's total long-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows

millions of Canadian dollars	Maturity		**2012**		2011
Emera – revolving credit facility (1)	June 2017	**$**	**700.0**	$	700.0
NSPI - revolving credit facility (2)	June 2017		**500.0**		500.0
GBPC - revolving credit facility	October 2013		**12.9**		-
BLPC - revolving credit facility			**8.0**		8.0
Bangor Hydro – revolving credit facility	September 2013		**79.6**		81.4
Total			**1,300.5**		1,289.4
Less:					
Borrowings under credit facilities			**626.2**		626.6
Letters of credit issued inside credit facilities			**14.8**		13.7
Use of available facilities			**641.0**		640.3
Available capacity under existing agreements		**$**	**659.5**	$	649.1

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $30 million and such advances are classified as short-term debt (note 23).
(2) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $50 million and such advances are classified as short-term debt (note 23).

Credit Facilities

On January 25, 2012, GBPC entered into an unsecured credit agreement with Scotiabank (Bahamas) Limited in the amount of $56.2 million USD. The proceeds of the credit agreement were used to finance the construction of a 52-MW power plant on Grand Bahama Island that is now complete and in service. The credit agreement bears interest at a rate of the three month LIBOR rate plus 1.2 percent and is repayable in forty equal, consecutive quarterly installments over a ten year period commencing October 25, 2012.

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

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

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

NSPI has an active commercial paper for up to $400 million, of which outstanding amounts are 100 percent backed by NSPI's bank line, which results in an equal amount of credit being considered drawn and unavailable.

Issuances

On January 31, 2012, Bangor Hydro completed the issuance of an unsecured $70 million USD senior note bearing interest at a rate of 3.61 percent per annum until January 31, 2022. The net proceeds of the note offering were used to repay borrowings under the revolving credit facility

On March 6, 2012, NSPI completed the issuance of $250 million Series Y Medium-Term Notes. The Series Y Notes bear interest at a rate of 4.15 percent per annum until March 5, 2042. The net proceeds of the note offering were used to repay short-term borrowings and for general corporate purposes.

Debt Covenants

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

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

Debt shelf prospectus

Emera
Emera's base shelf prospectus expired in June 2012.

NSPI
NSPI's base shelf prospectus expired in June 2012.

Long-Term Debt Maturities

As at December 31, long-term debt maturities, including capital lease obligations, for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2013	2014	2015	2016	2017	Greater than 5 years	Total
Emera	$ 0.8	$ 250.8	$ 0.5	$ 250.2	$ 302.5	$ 225.0	$ 1,029.8
NSPI	300.0	-	70.0	-	234.9	1,585.0	2,189.9
Bangor Hydro	19.9	34.3	4.5	4.5	24.4	124.0	211.6
MPS	-	-	-	-	-	22.5	22.5
GBPC	108.3	23.4	-	-	-	1.3	133.0
BLPC	8.0	11.2	4.0	0.9	1.1	23.9	49.1
Total	$ 437.0	$ 319.7	$ 79.0	$ 255.6	$ 562.9	$ 1,981.7	$ 3,635.9

25. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees; and plans providing non-pension benefits for its retirees in Nova Scotia, Maine, Barbados and Grand Bahama Island.

Benefit Obligation and Plan Assets

The changes in Benefit Obligation and Plan Assets, and the Funded Status for all plans were as follows:

For the millions of Canadian dollars	**2012**		Years ended December 31 2011	
Change in Projected Benefit Obligation and Accumulated Post-retirement Benefit Obligation	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Balance, January 1	**$ 1,165.4**	**$ 99.1**	$ 1,048.3	$ 88.2
Service cost	**18.0**	**2.8**	15.4	2.9
Plan participant contributions	**6.2**	**0.2**	6.2	0.2
Interest cost	**56.8**	**4.7**	56.6	4.7
Plan amendments	**(5.4)**	**-**	-	(0.1)
Benefits paid	**(55.1)**	**(6.9)**	(49.5)	(5.5)
Actuarial losses	**135.0**	**2.1**	85.6	8.0
Special termination	**1.5**	**0.5**	-	-
Foreign currency translation adjustment	**(1.5)**	**(1.2)**	2.8	1.2
Balance, December 31	**1,320.9**	**101.3**	1,165.4	99.6
Change in Plan assets				
Balance, January 1	**722.4**	**3.4**	724.2	3.4
Employer contributions	**163.2**	**6.7**	51.9	5.3
Plan participant contributions	**6.2**	**0.2**	6.2	0.2
Benefits paid	**(55.1)**	**(6.9)**	(49.5)	(5.5)
Actual return on assets, net of expenses	**66.1**	**0.3**	(11.9)	-
Foreign currency translation adjustment	**(0.2)**	**(0.2)**	1.5	-
Balance, December 31	**902.6**	**3.5**	722.4	3.4
Funded Status, end of year	**$ (418.3)**	**$ (97.8)**	$ (443.0)	$ (96.2)

As at December 31, the aggregate financial position for all pension plans where the Projected Benefit Obligation (PBO) or, for post-retirement benefit plans, the Accumulated Post-retirement Benefit Obligation (APBO), exceeds the plan assets was as follows:

Plans with PBO/APBO in excess of Plan assets

	2012		2011	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 1,318.5**	**$ 101.3**	$ 1,163.2	$ 99.6
Fair value of Plan Assets	**899.9**	**3.5**	720.0	3.4
Funded Status	**$ (418.6)**	**$ (97.8)**	$ (443.2)	$ (96.2)

The Accumulated Benefit Obligation ("ABO") for the defined benefit pension plans was $1,249.7 as at December 31, 2012 (2011 – $1,080.9 million). As at December 31, the aggregate financial position for all plans with an ABO in excess of the Plan assets was as follows:

Plans with ABO in excess of Plan assets

	2012	2011
millions of Canadian dollars	**Defined benefit pension plans**	Defined benefit pension plans
ABO	**$ 1,249.7**	$ 1,079.3
Fair value of Plan Assets	**899.9**	720.0
Funded Status	**$ (349.8)**	$ (359.3)

Balance Sheet

The amounts recognized in the Consolidated Balance Sheets as at December 31 consisted of the following:

	2012		2011	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Current liabilities	**$ (4.7)**	**$ (5.1)**	$ (4.6)	$ (4.2)
Long-term liabilities	**(413.7)**	**(92.7)**	(438.5)	(92.3)
Other asset (noncurrent)	**0.1**	**-**	0.3	-
Amount included in deferred tax asset	**22.3**	**6.3**	22.9	6.7
AOCL after tax adjustment	**589.4**	**14.1**	502.0	11.7
Net amount recognized at end of year	**$ 193.4**	**$ (77.4)**	$ 82.1	$ (78.1)

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCL. The following tables provide detail on the change in AOCL during fiscal 2012 relating to these items; and the composition of the year-end balance:

Accumulated Other Comprehensive Loss millions of Canadian dollars		Actuarial losses (gains)	Past service (gains) costs
Defined Benefit Pension Plans			
Balance, January 1	$	526.9 $	(0.5)
Amortized in current period		(32.8)	-
Current year addition to AOCL		126.9	(5.4)
Transfer to other regulatory asset (1)		(1.7)	-
Foreign currency translation adjustment		0.3	-
Balance, December 31	$	619.6 $	(5.9)
Non-pension benefits plans			
Balance, January 1	$	29.8 $	(10.8)
Amortized in current period		(2.2)	1.6
Current year addition to AOCL		2.0	-
Transfer to other regulatory asset (1)		0.2	-
Balance, December 31	$	29.8 $	(9.2)

(1) For MPS, as a result of regulatory accounting, any gain or loss is transferred to regulatory assets and amortized over the same period as the corresponding actuarial gains or losses.

		2012		2011
Accumulated Other Comprehensive Loss millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses	**$ 619.5**	**$ 29.8**	$ 525.4	$ 29.2
Past service (gains)	**(5.9)**	**(9.2)**	(0.5)	(10.8)
Total AOCL on a pre-tax basis	**613.6**	**20.6**	524.9	18.4
Less: Amount included in deferred tax asset	**(22.3)**	**(6.3)**	(22.9)	(6.7)
Net amount in AOCL after tax adjustment	**$ 591.3**	**$ 14.3**	$ 502.0	$ 11.7

The amounts in the foregoing table were not recognized in Emera's net periodic benefit cost as at December 31.

Benefit Cost Components		**2012**		2011
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 18.0**	**$ 2.8**	$ 15.4	$ 2.9
Interest cost	**56.8**	**4.7**	56.6	4.7
Expected return on plan assets	**(58.0)**	**(0.2)**	(56.3)	(0.2)
Current year amortization of:				
Actuarial losses	**32.8**	**2.2**	24.5	1.9
Past service costs (gains)	**-**	**(1.6)**	0.1	(2.0)
Special termination	**1.5**	**0.5**	-	-
Total	**$ 51.1**	**$ 8.4**	$ 40.3	$ 7.3

The expected return on plan assets is determined based on the market-related value of plan assets of $835.5 million as at January 1, 2012 (2011 – $803.8 million), adjusted for interest on certain cash flows during the year. The market related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight line basis into the market related value of assets over a five-year period.

Pension Plan Asset Allocations

Emera's investment policy includes discussion regarding the investment philosophy, the level of risk which the Company is prepared to accept with respect to the investment of the Pension Funds, and the basis for measuring the performance of the assets. Central to the policy is the target asset allocation by major asset categories. The objective of the target asset allocation is to diversify risk and to achieve asset returns that meet or exceed the plan's actuarial assumptions. The diversification of assets reduces the inherent risk in financial markets by requiring that assets be spread out amongst various asset classes. Within each asset class, a further diversification is undertaken through the investment in a broad basket of investment grade securities. Emera's target asset allocation is as follows:

Canadian Pension Plans

Asset Class	Target Range at Market		
Short term securities	0%	to	5%
Fixed income	30%	to	45%
Equities:			
Canadian	17%	to	27%
Non-Canadian (World)	36%	to	50%

Non-Canadian Pension Plans

Asset Class	Target Range at Market (weighted average)		
Short term securities	0%	to	5%
Fixed income	25%	to	53%
Equities:			
US	27%	to	63%
Non-US	15%	to	25%

For Bangor Hydro and MPS, the investment of the Non-Canadian pension assets is overseen by the management team. For GBPC, the investment of Non-Canadian pension assets is overseen by GBPA.

The fair values of investments as at December 31, 2012, by asset category, are as follows:

millions of Canadian dollars		**Level 1**	**Percentage**
Cash and cash equivalents	**$**	**38.8**	**4.3 %**
Equity Securities:			
Canadian equity		**159.5**	**17.7 %**
US equity		**216.1**	**24.0 %**
Other equity		**185.2**	**20.5 %**
Fixed income securities:			
Canadian government		**150.0**	**16.6 %**
US government		**14.8**	**1.6 %**
Other government		**0.7**	**0.1 %**
Corporate debt		**137.0**	**15.2 %**
Real estate		**0.3**	**- %**
Total	**$**	**902.4**	**100.0 %**

The fair value of investments as at December 31, 2011, by asset category, are as follows:

millions of Canadian dollars		Level 1	Percentage
Cash and cash equivalents	$	17.3	2.4 %
Equity Securities:			
Canadian equity		162.2	22.5 %
US equity		188.4	26.1 %
Other equity		89.6	12.4 %
Fixed income securities:			
Canadian government		141.7	19.6 %
US government		12.5	1.7 %
Other government		0.7	0.1 %
Corporate debt		109.7	15.2 %
Real estate		0.3	- %
Total	$	722.4	100.0 %

Refer to Note 1(Y), "*Summary of Significant Accounting Policies – Fair Value Measurement*," for more information on the fair value hierarchy and inputs used to measure fair value. All investments were deemed Level 1 for the years ended December 31, 2012 and 2011.

Investments in Emera or NSPI

As at December 31, 2012 and 2011, the pension funds do not hold any material investments in Emera Incorporated or NSPI securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

Canadian Post Retirement Benefit Plans

There are no assets set aside to pay for the Canadian post-retirement benefit plans. As is common in Canada, post-retirement health benefits are paid from general accounts on a pay as you go basis.

US Post Retirement Benefit Plans

Emera's US subsidiaries currently provide certain post-retirement health care and life insurance benefits for employees retiring after age 55 who meet eligibility requirements. Post-retirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify plans in whole or in part at any time.

Bangor Hydro and MPS provide retiree medical benefits to certain classes of employees. The Company's retiree medical expenses are incorporated into rate filings with its regulators and are recovered through its electric rates to customers.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (MMA) added prescription drug coverage to Medicare, with a 28 percent tax free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. Emera's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit post-retirement health care plan are at least "actuarially equivalent" to the standard drug benefits that are offered under Medicare Part D.

The Company received subsidy payments under Part D for the 2009 and 2010 plan years. Its 2011 Part D subsidy application with the Centers for Medicare and Medicaid Services was approved in December 2010, and the company expects to receive payment later this year.

Emera's target asset allocation for its US Post Retirement Benefits Plan is as follows:

Asset Class	Target Range at Market (weighted average)		
Short term securities	10%	to	50%
Fixed income	0%	to	40%
Equities:			
US	0%	to	60%
Non-US	0%	to	20%

The fair values of investments as at December 31, 2012, by asset category, are as follows:

millions of Canadian dollars		**Level 1**	**Percentage**
Cash and cash equivalents	**$**	**1.1**	**31.4 %**
Equity Securities:			
US equity		**1.6**	**45.7 %**
Fixed income securities:			
US government		**0.8**	**22.9 %**
Total	**$**	**3.5**	**100.0 %**

The fair value of investments as at December 31, 2011, by asset category, are as follows:

millions of Canadian dollars		Level 1	Percentage
Cash and cash equivalents	$	1.1	32.4 %
Equity Securities:			
US equity		1.5	44.1 %
Fixed income securities:			
US government		0.8	23.5 %
Total	$	3.4	100.0 %

Refer to Note 1(Y), "*Summary of Significant Accounting Policies – Fair Value Measurement*," for more information on the fair value hierarchy and inputs used to measure fair value. All investments were deemed Level 1 for the years ended December 31, 2012 and 2011.

Investments in Emera or NSPI

As at December 31, 2012 and 2011, the assets related to the post-retirement benefit plans do not hold any material investments in Emera Incorporated or NSPI securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

Cash Flows

The following table shows the expected cash flows for defined benefit pension and other post-retirement benefit plans:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefit plans
Expected Employer Contributions		
2013	$ 59.2	$ 6.9
Expected Benefit Payments		
2013	59.1	6.9
2014	65.9	7.3
2015	67.1	7.7
2016	71.8	8.1
2017	76.6	8.5
2018 - 2022	464.4	48.6

Assumptions

The following table shows the assumptions that have been used in accounting for defined benefit pension and other post-retirement benefit plans:

	2012			2011
(weighted average assumptions)	**Non-pension benefit plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Benefit obligation – December 31:				
Discount rate	**4.23 %**	**4.25 %**	4.96 %	4.80 %
Rate of compensation increase	**3.52 %**	**3.50 %**	3.52 %	3.50 %
Health care trend - initial (next year)	**- %**	**6.00 %**	- %	6.40 %
- ultimate	**- %**	**4.40 %**	- %	4.40 %
- year ultimate reached	**-**	**2014**	-	2014
Benefit cost for year ended December 31:				
Discount rate	**4.96 %**	**4.78 %**	5.51 %	5.56 %
Expected long-term return on plan assets	**6.85 %**	**- %**	7.08 %	- %
Rate of compensation increase	**3.52 %**	**3.50 %**	3.75 %	3.75 %
Health care trend - initial (current year)	**- %**	**6.40 %**	- %	6.90 %
- ultimate	**- %**	**4.45 %**	- %	4.55 %
- year ultimate reached	**-**	**2014**	-	2014

The expected long-term rate of return on plan assets is based on historical and projected real rates of return for the plan’s current asset allocation, and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined. The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

Nominal bond yields for certain maturities are provided by PC Bonds, a reliable source of bond rates in Canada. The bond yields for the missing maturities are interpolated linearly. The yields are then converted a spot-rate yield curve. This curve is used to determine the single accounting discount rate for select durations of typical pension plans. Lastly, the accounting discount rate for missing durations are then interpolated linearly. The discount rate is based on high-quality long-term Canadian corporate bonds, with maturities matching the estimated cash flows from the pension plan.

Sensitivity Analysis for Non-Pension Benefits Plans

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2012:

millions of Canadian dollars	Increase	Decrease
Service cost and interest cost	**$** 0.9	$ (0.8)
Accumulated post-retirement benefit obligation, December 31	10.8	(9.0)

Sensitivity Analysis for Defined Benefit Pension Plans

The impact on the 2012 benefit cost of a 25 basis point change (0.25 percent) in the discount rate and asset return assumptions is as follows:

millions of Canadian dollars	Increase	Decrease
Discount rate assumption	**$** (4.0)	$ 4.1
Asset rate assumption	(2.1)	2.1

Amounts to be Amortized in the Next Fiscal Year

The following table shows the amounts from the AOCL which is expected to be recognized as part of the net periodic benefit cost in fiscal 2013

millions of Canadian dollars	2013 Defined benefit pension plans	2013 Non-pension benefit plans
Actuarial gains (losses)	$ (47.5)	$ (2.2)
Past service gains	0.6	1.6
Total	$ (46.9)	$ (0.6)

Defined Contribution Plan

Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for 2012 was $6.9 million (2011 – $6.3 million).

26. OTHER CURRENT LIABILITIES

Other current liabilities consisted of the following:

As at millions of Canadian dollars	**December 31 2012**	December 31 2011
Accrued charges	**$ 72.1**	$ 69.0
Accrued interest on long-term debt	**41.6**	38.0
Sales taxes payable	**8.0**	12.8
Dividends payable	**-**	2.0
Other	**9.2**	5.4
	$ 130.9	$ 127.2

27. ASSET RETIREMENT OBLIGATIONS

AROs mostly relate to the reclamation of land at the thermal, hydro, and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment. Certain hydro, transmission and distribution assets may have additional ARO that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the fair value of any related ARO cannot be made at this time.

The change in ARO for the years ended December 31 is as follows:

millions of Canadian dollars		2012	2011
Balance, January 1	$	**99.9**	$ 141.8
Additions due to acquisition		**-**	2.3
Liabilities settled		**(1.2)**	(1.3)
Accretion included in depreciation expense		**7.0**	4.5
Accretion deferred to regulatory asset (included in property, plant and equipment)		**(2.0)**	1.9
Revisions in estimated cash flows		**(8.7)**	(49.3)
Balance, December 31	**$**	**95.0**	$ **99.9**

As at December 31, 2012 and 2011, some of the Company’s transmission and distribution assets may have additional conditional ARO which are not recognized in the financial statements as the fair value of these obligations could not be reasonably estimated given there is insufficient information to do so. Management will continue to monitor these obligations and a liability will be recognized in the period in which an amount becomes determinable.

During Q4, 2011, Emera Brunswick Pipeline’s estimated cash flows with respect to its ARO were updated as a result of the National Energy Board’s new guidelines for the calculation of reclamation and abandonment costs for Canadian pipelines. The change resulted from a change in the estimate of future reclamation and abandonment costs.

During Q2 2011, NSPI’s estimated future cash flows with respect to ARO were updated to reflect the results of a settlement agreement with stakeholders which was approved by the UARB, following the completion of a depreciation study. The changes resulted from a change in estimates of retirement dates and future decommissioning costs. The new accretion rates are effective January 1, 2012.

28. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2012, contractual commitments (excluding pensions and other post-retirement obligations, long-term debt, and AROs) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2013	2014	2015	2016	2017	Thereafter	Total
Purchased power (1)	$ 151.2	$ 155.2	$ 153.3	$ 119.3	$ 115.7	$ 1,157.5	$ 1,852.2
Coal, biomass, oil and natural gas supply	126.8	69.8	21.2	17.3	-	-	235.1
Transportation (2)	55.6	34.5	19.8	4.6	2.0	9.4	125.9
Long-term service agreements (3)	30.2	22.8	21.4	16.1	12.7	35.0	138.2
Capital projects	70.4	3.0	4.0	-	-	-	77.4
Leases (4)	3.4	3.3	3.3	2.8	2.6	13.5	28.9
Other	25.3	0.5	0.5	0.5	0.5	0.5	27.8
	$ 462.9	$ 289.1	$ 223.5	$ 160.6	$ 133.5	$ 1,215.9	$ 2,485.5

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

(2) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on various pipelines.

(3) Long-term service agreements: outsourced management of the Company's computer and communication infrastructure, vegetation management, maintenance of certain generating equipment, and services related to a generation facility and wind operating agreements.

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

B. Legal Proceedings

A number of individuals who live in proximity to the NSPI’s Trenton generating station have filed a statement of claim for an unspecified amount against NSPI in respect of emissions from the operation of the plant for the period from 2001 forward. The plaintiffs claim unspecified damages as a result of interference with enjoyment of, or damage to, their property. NSPI has filed a defense to the claim. The outcome of this litigation, and therefore an estimate of any contingent loss, is not determinable.

On September 30, 2011, a consortium of New England Commission's Public Advocates and End Users ("Complainants") filed a complaint with the FERC alleging that the 11.14 percent base ROE under the ISO-New England Open Access Transmission Tariff ("OATT") is unjust and unreasonable. The Complainants offered evidence and testimony that the appropriate ROE should be no more than 9.0 percent. On October 20, 2011, the New England Transmission Owners ("NETOs"), of which the Bangor Hydro is one, answered the complaint and filed testimony alleging that the 11.14 percent ROE continues to be just and reasonable. On December 27, 2012, a second group of consumer advocates including Environment Northeast filed a complaint at FERC on similar grounds, arguing that an ROE of 8.7 percent was appropriate. These matters are currently pending before the FERC. The outcome of these matters, and therefore an estimate of any contingent loss, is not determinable.

On October 31, 2011, MF Global Holding Ltd., the parent company of MF Global Inc. ("MFG"), a futures commission merchant used by Emera Energy for natural gas and electricity futures filed for Chapter 11 bankruptcy. Emera Energy was able to transfer its open future positions to other brokers; however $5.46 million USD of its posted margin was frozen with MFG and Emera Energy was unable to transfer these funds. Legal proceedings related to the bankruptcy were initiated and expected to involve cross-border insolvency proceedings as a result of MFG's global affiliates. The outcome of the bankruptcy proceedings was not determinable. Although management expected to recover the majority of the frozen funds, a provision was recognized as at December 31, 2011 and the net amount was reclassified to "Other long-term assets" on the Consolidated Balance Sheets. In Q2 2012, Emera Energy sold its MFG claims to a third party for an amount in excess of the net amount classified as "Other long-term assets".

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

C. Environment

Emera's activities are subject to a broad range of federal, provincial, state, regional and local laws and environmental regulations, designed to protect, restore, and enhance the quality of the environment including air, water and solid waste. Emera estimates its environmental capital expenditures, excluding AFUDC, based upon present environmental laws and regulations were approximately $49.7 million during 2012 and are estimated to be $375.0 million from 2013 through 2016. Amounts that have been committed to are included in "Capital projects" in the commitments table in note 28A. The estimated expenditures do not include costs related to possible changes in the environmental laws or regulations and enforcement policies may be enacted in response to issues such as climate change and other pollutant emissions.

NSPI

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

Conformance with legislative and NSPI requirements are verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the audits completed to December 31, 2012.

On June 29, 2012, the federal budget omnibus Bill C-38 was given Royal Assent. Part 3 of the Bill (Responsible Resource Development) included a complete repeal of the previous Canadian Environmental Assessment Act ("CEAA") and replacement with a new CEAA 2012. There were also substantial changes to the longstanding Fisheries Act. While sweeping in nature, most of these changes are consistent with NSPI's environmental processes and actions. NSPI is currently working with federal officials to further understand the details of the changes and to provide input as complementary policies are developed.

Poly Chlorinated Bi-Phenol Transformers

In response to the Canadian Environmental Protection Act 1999, 2008 Poly Chlorinated Bi-Phenol ("PCB") Regulations to phase out electrical equipment and liquids containing PCBs, NSPI has implemented a program to eliminate transformers and other oil filled electrical equipment on its system that do not meet the 2008 PCB Regulations Standard by 2014. In addition, there is a capital program to destroy all confirmed PCB contaminated pole mount transformers taken out of service through attrition. The combined total cost of these projects is estimated to be $27.2 million and, as at December 31, 2012, approximately $10.2 million (December 31, 2011 – $7.8 million) has been spent to date. NSPI has recognized an ARO of $11.8 million as at December 31, 2012 (December 31, 2011 – $20.6 million) associated with the PCB phase-out program.

ENL

The Maritime Link Project, a sub-sea cable transmission project between Newfoundland and Nova Scotia, is undergoing environmental assessment under the Canadian Environmental Assessment Act, the Newfoundland and Labrador Environmental Protection Act, and the Nova Scotia Environment Act. The Environmental Assessment Report for the Maritime Link was submitted on January 10, 2013.

Maine Utilities

Poly Chlorinated Bi-Phenol Transformers

In response to a Maine environmental regulation to phase out PCB transformers, the Maine Utilities implemented multi-year programs to eliminate transformers on their systems that do not meet the new State environmental guidelines. The Maine Utilities completed their programs in 2011. The cost of testing the transformers is expensed as incurred; replacement transformers and the cost to install those transformers are capitalized. As of December 31, 2011 all transformers were remediated and are PCB-free in this effort; the total cumulative expenditures associated with the Maine Utilities' programs were $4.4 million.

Caribbean Utilities

The Caribbean utilities have implemented a Health Safety Environmental and Management system to assist in safeguarding the health and safety of employees, contractors and customers while ensuring protection of the environment.

D. Principal Risks and Uncertainties

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

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach.

Regulatory Risk

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

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

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

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

Changes in Environmental Legislation

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

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

Commercial Relationships

NSPI

NSPI's five largest customers contributed approximately 7.1 percent (2011 – 13.3 percent) for the twelve months ended December 31, 2012. The loss of a large customer could have a material effect on NSPI's operating revenues. NSPI works to mitigate this risk through operational adjustments and cost management as well as the regulatory process. As discussed below, two large industrial customers were not operating for a large portion of 2012; however, the financial impact of this was deferred as approved by the UARB through the FCR mechanism.

In September 2011, a large customer was granted creditor protection under the Companies' Creditor Arrangement Act ("CCAA") and suspended operations. On September 28, 2012, the customer's Plan of Arrangement pursuant to the CCAA process was finalized; the CCAA creditor protection ceased, and a new owner resumed a significant portion of the operations under a load retention tariff. As part of the CCAA process, NSPI set-off an outstanding receivable balance of $11.6 million against amounts owing from NSPI to the customer.

Another large customer indefinitely idled their mill in June 2012.

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

Brunswick Pipeline

Brunswick Pipeline has a 25 year firm service agreement with Repsol Energy Canada ("REC"). The pipeline was used solely in 2012 and 2011 to transport natural gas from the Canaport LNG terminal in Saint John, New Brunswick to the United States border for REC. The risk of non-payment is mitigated as Repsol YPF, S.A ("Repsol"), the parent company of REC, has provided Brunswick Pipeline with a guarantee for all RECs' payment obligations under the firm service agreement. As at December 31, 2012 the net investment in direct financing lease with Repsol was $491.9 million (December 31, 2011 – $493.8 million).

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

Bayside Power

Bayside Power sells all of its power during the winter months, November through March, to NB Power in accordance with a long-term purchase power agreement ("PPA"). Revenue from this PPA contributed 55.7 percent (2011 – 46.5 percent) to Bayside Power's electric revenues for the twelve months ended December 31, 2012. The PPA expires March 31, 2021, with an option to renew for an additional five year term, provided both parties consent to the renewal.

Labour Risk

Certain Emera employees are subject to collective labour agreements. Approximately 53 percent of the full-time and term employees at NSPI, BLPC, GBPC, Bangor Hydro, Utility Services, and MPS are represented by local unions.

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

Approximately 15 percent of the labour force is covered by collective labour agreements that have or will expire within the next twelve months. Where collective labour agreements have expired, negotiations for new agreements have commenced and are ongoing. Emera seeks to manage this risk through ongoing discussions with local unions.

Interest Rate Risk

The Company utilizes a combination of fixed and variable rate debt financing for operations and capital expenditures resulting in an exposure to interest rate risk. The Company seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

Commodity Prices and Foreign Exchange Rate Fluctuations

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

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

E. Collaborative Arrangement

Bangor Hydro

Through Bangor Hydro, the Company is a party to a collaborative arrangement with National Grid Transmission Services Corporation to develop the Northeast Energy Link ("NEL") Project. The cost of development activities, including acquisition of land in the transmission corridor and acquisition of necessary governmental and regulatory permits and approvals, are shared equally between the Company and National Grid. Bangor Hydro has deferred $2.8 million USD of costs associated with the NEL project as at December 31, 2012 (December 31, 2011 - $2.5 million USD), reported in the Consolidated Balance Sheets in "Other" as part of other assets.

F. Guarantees and Letters of Credit

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

- NSPI has provided a limited guarantee for the indebtedness of Renewable Energy Services Ltd. ("RESL") under a $23.5 million loan agreement between RESL and a third party lender. As at December 31, 2012, RESL's indebtedness under the loan agreement was $20.8 million. NSPI holds a security interest in the present and future assets by RESL in connection with a wind energy project at Point Tupper, Nova Scotia. For further information see note 33.

- Emera has provided a guarantee to the Long Island Power Authority ("LIPA") on behalf of Bear Swamp for Bear Swamp's long-term energy and capacity supply agreement ("PPA") with LIPA, which expires on April 30, 2021. The guarantee is for 50 percent of the relevant obligations under the PPA up to a maximum of $5.1 million USD. As at December 31, 2012, the fair value of the PPA was positive.

- Standby letters of credit in the amount of $7.3 million USD for the benefit of third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one year term and are renewed annually as required.

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

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

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

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

- Letters of credit totaling $23.9 million USD to secure principal and interest payments related to Maine Public Utilities Financing Bank bonds issued on behalf of MPS, related to qualifying distribution assets. The letters of credit expire in November 2013.

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

29. COMMON STOCK

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

	2012			2011		
Issued and outstanding:	millions of shares		millions of Canadian dollars	millions of shares		millions of Canadian dollars
Balance, January 1	**122.83**	**$**	**1,385.0**	114.62	$	1,137.8
Issuance of common stock	**5.91**		**193.2**	6.36		196.0
Issued for cash under Purchase Plans at market rate	**1.55**		**52.0**	1.40		42.8
Discount on shares purchased under Dividend Reinvestment Plan	**-**		**(2.3)**	-		(1.8)
Options exercised under senior management share option plan	**0.69**		**13.9**	0.45		8.8
Stock-based compensation	**-**		**1.9**	-		1.4
Balance, December 31, 2012	**130.98**	**$**	**1,643.7**	122.83	$	1,385.0

In December 2012, Emera completed an offering of 5,905,250 common shares, at $34.10 per common share, for net proceeds of approximately $193.2 million.

In March 2011, Emera issued 6,359,500 common shares, which included the exercise of the over-allotment option of 829,500 common shares. The shares were issued at $31.70 per share for net proceeds of approximately $196.0 million.

As at December 31, 2012, there were the following common shares reserved for issuance: 2.7 million (2011 – 3.4 million) under the senior management stock option plan, 0.1 million (2011 – 0.3 million) under the employee common share purchase plan and 3.7 million (2011 – 5.0 million) under the dividend reinvestment plan. The issuance of common shares under the current or proposed common share compensation arrangements will not exceed ten percent of Emera's outstanding common shares.

30. CUMULATIVE PREFERRED STOCK

Authorized:
Unlimited number of First Preferred shares, issuable in series.
Unlimited number of Second Preferred shares, issuable in series.

Issued and Outstanding:	Millions of Shares		Preferred Stock Millions of Canadian dollars
Balance, December 31, 2011 - First Preferred Shares Series A	6.0	$	146.7
Issuance of First Preferred Shares Series C	10.0		244.9
Balance, December 31, 2012	16.0	$	391.6

First Preferred Shares, Series C

On June 7 2012, Emera issued ten million 4.10 percent Cumulative Six-Year Rate Reset First Preferred Shares, Series C ("First Preferred Shares, Series C"). The First Preferred Shares, Series C were issued at $25.00 per share for gross proceeds of $250.0 million and net proceeds of $244.9 million.

As the First Preferred Shares, Series C are neither redeemable at the option of the shareholder nor have a mandatory redemption date, they are classified as equity and the associated dividends will be deducted on the Consolidated Statements of Income immediately before arriving at "Net income attributable to common shareholders" and will be shown on the Consolidated Statement of Changes in Equity as a deduction from "Retained earnings".

The holders of First Preferred Shares, Series C are entitled to receive fixed cumulative preferred cash dividends in the amount of $1.025 per share per annum for each year up to but excluding August 15, 2018, as and when declared by the Board of Directors. For each five-year period after August 15, 2018, the holders of Series C Shares will be entitled to receive reset fixed cumulative preferred cash dividends. The reset annual dividends per share will be determined by multiplying the $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the application reset date plus 2.65 percent.

On August 15, 2018 and on August 15 every five years thereafter, the Company has the right to redeem all or any part of the then outstanding Frist Preferred Shares, Series C by the payment of an amount in cash of $25 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

The holders of First Preferred Shares, Series C will, subject to the automatic conversion provisions and the right of the Company to redeem those shares, have the right, at their option, to convert any of all of their shares into an equal number of Cumulative Floating Rate First Preferred Shares, Series D on August 15, 2018 and on August 15 every five years thereafter.

The holders of Series D Shares will be entitled to receive floating rate cumulative preferred cash dividends, as and when declared by the Board of Directors. The First Preferred Shares, Series D have the same characteristic as Series C, with the exception of the calculation of the floating dividend rate for the Series D shares being the sum of the T-bill rate plus 2.65 percent.

The holders of First Preferred Shares, Series D will, subject to the automatic conversion provisions and the right of the company to redeem those shares, have the right, at their option, to convert any or all of their Series D Shares into an equal number of Series C Shares on August 15, 2023 and on August 15 every five years thereafter.

On August 15, 2023 and on August 15 every five years thereafter, the Company has the right to redeem all or any part of the then outstanding First Preferred Shares, Series D by the payment of an amount in cash of $25 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption or $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption in the case of redemptions on any other date after August 15, 2018.

The First Preferred Shares of each series rank on parity with each other and every other series of First Preferred Shares and are entitled to preference over the common shares of the Company and over any other shares of the Company ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up of the Company.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares will be entitled to attend any meeting of the shareholders of the Company and to vote at any such meeting.

First Preferred Shares, Series A

In June 2010, Emera issued six million 4.40% Cumulative Five-Year Rate Reset First Preferred Stock, Series A ("First Preferred Stock, Series A"). The $150 million First Preferred Stock, Series A were issued at $25.00 per share for net proceeds of approximately $146.7 million.

As the First Preferred Shares, Series A are neither redeemable at the option of the shareholder nor have a mandatory redemption date, they are classified as equity and the associated dividends will be deducted on the consolidated statements of earnings immediately before arriving at "Net earnings attributable to common shareholders" and will be shown on the consolidated statement of equity as a deduction from retained earnings.

The First Preferred Shares, Series A are entitled to receive fixed cumulative preferred cash dividends in the amount of $1.10 per share per annum for each year up to and including May 15, 2015. For each five-year period after this date, the holders of First Preferred Shares, Series A are entitled to receive reset fixed cumulative preferred cash dividends. The reset annual dividends per share will be determined by multiplying the $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 1.84 percent.

The holders of First Preferred Shares, Series A will have the right, at their option, to convert their shares into an equal number of Cumulative Floating Rate First Preferred Shares, Series B of the Company on August 15, 2015 and every five years thereafter.

The First Preferred Shares, Series B have the same characteristics as the Series A shares, with the exception of the calculation of the floating dividend rate for the Series B shares being the sum of the T-bill rate plus 1.84 percent.

The holders of the First Preferred Shares, Series B will have the right, at their option, to convert their shares into an equal number of Series A shares of the Company on August 15, 2020 and every five years thereafter.

On August 15, 2015 and August 15, 2020 respectively and on August 15 every five years thereafter, the Company has the right to redeem for cash the outstanding First Preferred Shares, Series A or B in whole or in part at a price of $25 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

The First Preferred Shares of each series rank on a parity with the First preferred Shares of every other series and are entitled to a preference over a the Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares will be entitled to attend any meeting of shareholders of the Company and to vote at any such meeting.

31. NON-CONTROLLING INTEREST IN SUBSIDIARIES

Non-controlling interest in subsidiaries as at December 31 consisted of the following:

millions of Canadian dollars		**2012**		2011
Preferred shares of NSPI	**$**	**132.2**	$	132.2
Preferred shares of Bangor Hydro		**0.4**		0.4
BLPC		**63.1**		60.6
ICDU		**31.7**		31.3
	$	**227.4**	$	224.5

Preferred shares of NSPI:

Authorized:
Unlimited number of First Preferred shares, issuable in series
Unlimited number of Second Preferred shares, issuable in series

		2012			2011
Issued and outstanding:	**Millions of shares**	**$**	**Millions of dollars**	Millions of shares	**$**	Millions of dollars
Outstanding as at December 31, 2012	**5.4**	**$**	**132.2**	**5.4**	**$**	132.2

NSPI Series D First Preferred Stock:

On and after October 15, 2015, Series D First Preferred Stock is redeemable by NSPI, in whole at any time or in part from time to time at $25 per share plus accrued and unpaid dividends. NSPI also has the option, commencing October 15, 2015, to exchange the Series D First Preferred Stock into Emera common stock determined by dividing $25 by the greater of $2 and the market price of the Emera common stock.

Commencing on and after January 15, 2016, with prior notice and prior to any dividend payment date, each Series D First Preferred Stock will be exchangeable at the option of the holder into fully paid and freely tradable Emera common stock determined by dividing $25 by the greater of $2 and the market price of the Emera common stock, subject to the right of NSPI to redeem such stock for cash or to cause the holders of such stock to sell on the exchange date all or any part of such stock to substitute purchasers found by NSPI. NSPI will pay all accrued and unpaid dividends to the exchange date.

Each Series D First Preferred Stock is entitled to a $1.475 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 fifteenth day of January, April, July and October of each year.

The First Preferred Shares of each series rank on a parity with the First preferred Shares of every other series issued by NSPI and are entitled to a preference over NSPI's Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of NSPI in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event NSPI fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of NSPI's First Preferred Shares will be entitled to attend any meeting of shareholders of NSPI and to vote at any such meeting.

32. STOCK-BASED COMPENSATION

EMPLOYEE COMMON STOCK PURCHASE PLAN AND COMMON SHAREHOLDERS DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

The Company has an Employee Common Share Purchase Plan to which employees make cash contributions for the purpose of purchasing common shares. The Company also contributes to the plan a percentage of the employees' contributions. The plan allows the reinvestment of dividends. The maximum aggregate number of common shares reserved for issuance under this plan is 2.0 million common shares.

The Company uses the fair value based method to measure the compensation expense related to its employee purchase plan. Compensation cost recognized for the year ended December 31, 2012 was $0.8 million (2011 – $0.7 million) and is included in "Operating, maintenance and general" on the Consolidated Statements of Income.

The Company also has a Common Shareholders Dividend Reinvestment and Share Purchase Plan ("Dividend Reinvestment Plan"), which provides an opportunity for shareholders to reinvest dividends and to make cash contributions for the purpose of purchasing common shares. Effective September 25, 2009, Emera changed its Dividend Reinvestment Plan to provide for a discount of up to 5 percent from the average market price of Emera's common shares for common shares purchased in connection with the reinvestment of cash dividends under the Plans.

STOCK-BASED COMPENSATION PLANS

Stock Option Plan

The Company has a stock option plan that grants options to senior management of the Company for a maximum term of ten years. The option price of the stock options is the closing market price of the stocks on the day before the option is granted. The maximum aggregate number of shares issuable under this plan is 6.7 million shares.

All options granted to date are exercisable on a graduated basis with up to 25 percent of options exercisable on the first anniversary date and in further 25 percent increments on each of the second, third and fourth anniversaries of the grant. If an option is not exercised within ten years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The total number of stocks to be optioned to any optionee shall not exceed five percent of the issued and outstanding common stocks 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 termination for other than just cause, such option may, subject to the terms thereof and any other terms of the plan, be exercised at any time within the 24 months following the date the optionee retires, but in any case prior to the expiry of the option in accordance with its terms.

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

The Company uses the fair value based method to measure the compensation expense related to its stock-based compensation and recognizes the expense over the vesting period on a straight-line basis. The fair value of stock option awards granted was estimated on the date of grant using a Black-Scholes valuation model. The expected term of the option awards is calculated based on historical exercise behavior and represents the period of time that options are expected to be outstanding. The risk-free interest rate is based on the Bank of Canada seven-year government bond yields. The expected dividend yield incorporates current dividend rates as well as historical dividend increase patterns. Emera's expected stock price volatility was estimated using its three-year historical volatility.

The following table shows the weighted-average fair values per stock option along with the assumptions incorporated into the valuation models for options granted:

	2012	2011
Weighted average fair value per option	**$ 2.51**	$ 3.37
Expected term	**6.5 years**	7.0 years
Risk-free interest rate	**1.58 %**	3.88 %
Expected dividend yield	**4.32 %**	4.89 %
Expected volatility	**16.38 %**	14.32 %

A summary of stock option activity for the year ended December 31, 2012 and information related to outstanding and exercisable stock options as at December 31, 2012 is presented in the following table:

	Stock Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (millions of Canadian dollars)
Outstanding as at December 31, 2011	1,831,397	$ 22.44	6.4	$ 19.4
Granted	404,343	33.44		-
Exercised	(692,747)	20.14		9.6
Forfeited	(9,650)	32.89		-
Outstanding as at December 31, 2012	1,533,343	$ 26.32	6.9	$ 12.9
Exercisable as at December 31, 2012	744,575	$ 22.38		$ 9.2

Compensation cost recognized for stock options for the year ended December 31, 2012 was $0.4 million (2011 – $0.7 million), which is included in "Operating, maintenance and general" on the Consolidated Statements of Income.

As at December 31, 2012, the compensation cost related to unvested and outstanding stock options was $1.4 million and expected to be recognized over a weighted-average period of 2.6 years (2011– $0.9 million, 3.3 years). Cash received from option exercises for the year ended December 31, 2012 was $13.9 million (2011 – $8.7 million). The total intrinsic value of options exercised for the year ended December 31, 2012 was $9.6 million (2011 – $6.1 million). The range of exercise prices for the options outstanding as at December 31, 2012 was $15.73 to $32.06 (2011 – $15.73 to $12.06).

Share Unit Plans

The Company has deferred share unit ("DSU") and performance share unit ("PSU") plans. The DSU and PSU liabilities are marked-to-market at the end of each period based on the common share price at the end of the period.

Deferred Share Unit Plan

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

When incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera 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 average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Payments are usually made in cash. At the sole discretion of the Management Resources and Compensation Committee ("MRCC"), payments may be made in the form of actual shares.

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

A summary of the activity related to employee and director DSU's for the year ended December 31, 2012 is presented in the following table:

	Employee DSU	Weighted Average Grant Date Fair Value	Director DSU	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2011	362,921	$ 21.91	196,104	$ 25.34
Granted including DRIP	44,623	29.01	51,661	33.91
Exercised	(16,553)	22.05	(31,581)	23.78
Outstanding as at December 31, 2012	390,991	$ 22.34	216,184	$ 26.16

Compensation cost recognized for employee and director DSU for the year ended December 31, 2012 was $3.9 million (2011 – $3.5 million). Compensation cost capitalized for employee and director DSU for the year ended December 31, 2012 was $0.2 million (2011 – $0.1 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2012 were $1.3 million (2011 – $1.1 million), $0.4 million was offset with regulatory assets and regulatory liabilities (2011 – $0.3 million).

Performance Share Unit Plan

Under the PSU plan, executive and senior employees are eligible for long-term incentives payable through the PSU plan. PSUs are granted annually for three-year overlapping performance cycles. PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Dividend equivalents are awarded and are used to purchase additional PSUs, also referred to as DRIP. The PSU value varies according to the Emera common share market price and corporate performance.

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

A summary of the activity related to employee PSU's for the year ended December 31, 2012 is presented in the following table:

	Employee PSU		Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2011	354,458	**$**	29.01
Granted including DRIP	143,171		32.54
Exercised	(125,494)		21.41
Forfeited	(12,974)		28.99
Outstanding as at December 31, 2012	359,161	**$**	29.59

Compensation cost recognized for the PSU plan for the year ended December 31, 2012 was $5.1 million (2011 – $3.7 million). Compensation cost capitalized for employee PSU for the year ended December 31, 2012 was $0.3 million (2011 – $0.2 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2012 were $1.7 million (2011 – $1.2 million).

Non-Vested Stock-Based Compensation Plans

For the year ended December 31, 2012, a summary of activity from the different plans is presented in the following table:

				Share Unit Plan					
	Stock Option Plan			**DSU Plan**			**PSU Plan**		
	Number of options		Weighted Average Grant Date Fair Value	Number of share units		Weighted Average Grant Date Fair Value	Number of share units		Weighted Average Grant Date Fair Value
Non-vested shares as at December 31, 2011	670,000	$	30.38	47,729	$	21.60	228,964	$	31.86
Granted	404,343		33.44	44,623		29.01	143,171		32.25
Vested	(275,925)		24.42	(60,902)		27.07	(100,524)		31.19
Forfeited	(9,650)		32.89	-		-	(12,974)		28.99
Non-vested shares as at December 31, 2012	788,768	$	30.04	31,450	$	21.52	258,637	$	31.88

Fully-Vested Stock-Based Compensation Plans

			Share Unit Plan	
		Stock Option Plan	**DSU Plan**	**PSU Plan**
Outstanding				
Number of options/share units		1,533,343	575,725	100,524
Weighted-average exercise price of options	$	26.32	-	-
Aggregate intrinsic value of options/ Fair value of share units	$	12,914,544 $	20,000,687 $	3,429,204
Weighted-average remaining contractual terms of options/share units		6.9 years	-	-
Currently Exercisable				
Number of options/share units		744,575	-	-
Weighted-average exercise price of options	$	22.38	**-**	**-**
Aggregate intrinsic value of options/ Fair value of share units	$	9,206,658	**-**	**-**
Weighted-average remaining contractual terms of options/share units		5.5 years	-	-

The total fair value of shares vested for all the plans was $49.4 million for the year ended December 31, 2012 (2011 - $60.6 million). The weighted-average grant date fair value of shares, granted for all the plans, for the year ended December 31, 2012 was $23.74 (2011 - $23.42).

33. VARIABLE INTEREST ENTITIES

The Company performs ongoing analysis to assess whether it holds any VIEs. To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where Emera is not deemed the primary beneficiary, the VIE is not recorded in the Company's consolidated financial statements.

LPH has established a SIF primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. LPH holds a variable interest in the SIF for which it was determined that LPH was the primary beneficiary and, accordingly, the SIF must be consolidated by LPH. In its determination that LPH controls the SIF, management considered that in substance the activities of the SIF are being conducted on behalf of LPH's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because LPH, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF.

NSPI holds a variable interest in RESL, a VIE for which it was determined that NSPI was not the primary beneficiary since it does not have the controlling financial interest of RESL. NSPI has provided a guarantee with no set term for the indebtedness of RESL under a loan agreement between RESL and a third party lender for $23.5 million, in support of which NSPI holds a security interest in the present and future assets owned by RESL, in conjunction with a wind energy project at Point Tupper, Nova Scotia. The guarantee arose in connection with NSPI's participating in the foregoing wind energy project which is operated by RESL. Under a purchased power agreement, NSPI purchases, at a fixed price, 100 percent of the power generated by the project. A default by RESL, under its loan agreement, would require NSPI to make payment under the guarantee. As at December 31, 2012, RESL's indebtedness under the loan agreement was $20.8 million (December 31, 2011 – $21.9 million), and NSPI has not recorded a liability in relation to the guarantee.

Bangor Hydro holds a variable interest in Chester Static Var Compensator ("SVC"), a VIE for which it was determined that Bangor Hydro was not the primary beneficiary since it does not have the controlling financial interest of Chester SVC. A subsidiary of Bangor Hydro is a 50 percent general partner in Chester SVC, which owns electrical equipment that supports a major transmission line. A wholly-owned subsidiary of Central Maine Power Company owns the other 50 percent interest. Chester SVC is 100 percent debt financed and accordingly the partners have no equity interest; and the holders of the SVC notes are without recourse against the partners or their parent companies.

The Company has identified certain long-term purchase power agreements that could be defined as variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

Emera's consolidated VIE is recorded as an "Available-for-sale investment". The following table provides information about Emera's portion of consolidated and unconsolidated VIEs:

As at		December 31, 2012		December 31, 2011	
millions of Canadian dollars		**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Consolidated VIE					
BLPC SIF Available-for-sale investment		**$ 61.7**	**$ 61.7**	$ 54.1	$ 54.1
Unconsolidated VIEs in which Emera has Variable Interests					
RESL		**-**	**23.5**	-	23.5
Chester SVC		**-**	**-**	-	-

For the years ended, December 31 2012 and 2011, the Company has not identified any new VIEs.

34. ACQUISITIONS

Light & Power Holdings Ltd.

On January 25, 2011, Emera acquired 7.2 million shares of LPH, the parent company of BLPC, a vertically-integrated utility and the sole provider of electricity on the island of Barbados with a franchise to produce, transmit and distribute electricity on the island until 2028, for total cash consideration of $92.6 million CAD ($92.8 million USD). As a result, Emera became the majority shareholder of LPH, with a total interest of 80.1 percent. This investment was made to increase Emera's regulated transmission, distribution and generation portfolio.

Prior to this transaction, Emera owned 38.3 percent of LPH with a carrying value of $113.5 million CAD ($113.8 million USD). The fair value of Emera's interest in LPH immediately prior to the acquisition date was $84.8 million CAD ($85.0 million USD).

The fair value of the assets of a regulated utility are generally deemed to equal book value (rate base) given the regulated utility's earnings are a function of its rate base, as determined by the regulator. The purchase price was negotiated between arms-length parties. The differential between the two amounts resulted in Emera recording a gain on acquisition of $ 28.2 million, which Emera has recorded as a non-taxable gain in "Other income (expenses), net" on Emera's Consolidated Statements of Income for the year ended December 31, 2011.

The valuation technique used to measure the acquisition-date fair value of the assets and liabilities of LPH was book value for regulated assets given the regulatory environment in which BLPC operates. Non-regulated assets were measured based on recent transactions. Accordingly, a third party valuation of assets and liabilities was not performed.

The purchase price allocation has been finalized. The total purchase price has been allocated to the fair value of assets and liabilities as follows:

		millions of Canadian dollars
Cash and cash equivalents	$	58.4
Restricted cash		12.3
Receivables, net		23.4
Income tax receivable		0.2
Inventory		16.3
Prepaid expenses		2.9
Property, plant and equipment		292.0
Available-for-sale investments		52.5
Other non-current assets		1.6
Current portion of long-term debt		(7.5)
Accounts payable		(33.7)
Other current liabilities		(5.3)
Long-term debt		(43.1)
Deferred income taxes		(9.5)
Regulatory liabilities		(62.7)
ARO		(2.2)
Other long-term liabilities		(2.5)
Gain on business acquisition (1)		(28.2)
Non-controlling interest		(58.2)
Total purchase consideration	$	206.7

(1) The gain shown above represents the net effect of the gain on acquisition of $56.3 million net of a loss of $28.1 million on a business combination achieved in stages, which requires the revaluation of the existing interest to the implied value from the second investment at the date of acquiring control. The gain is included in “Other income (expenses) net” in the Consolidated Statements of Income.

The Company has included operating revenues of $282.4 million and net income attributable to common shareholders of $12.0 million for BLPC in its consolidated net income attributable to common shareholders for fiscal 2011 related to the period subsequent to January 25, 2011.

The Company also incurred $2.0 million in acquisition-related costs of which $0.5 million was recorded in 2010 and $1.5 million was recorded in 2011. These costs are included in “Operating, maintenance and general expense” in the Consolidated Statements of Income.

35. COMPARATIVE INFORMATION

Effective Q1 2012, the Company classified partnership income tax expense previously recorded as a reduction in “Income from equity investments” to “Income tax expense (recovery)” in the Consolidated Statements of Income. Prior year comparatives have been retrospectively reclassified with $12.8 million previously recorded as a reduction in “Income from equity investments for the year ended December 31, 2011, reclassified to “Income tax expense (recovery)” in the Consolidated Statements of Income.

36. SUBSEQUENT EVENTS

On January 16, 2013, GBPC issued thirty-two thousand non-voting cumulative redeemable perpetual variable preference shares at a price of $1,000.00 Bahamian per share, for net proceeds of $30.9 million Bahamian.