EMERA INCORPORATED

Consolidated Financial Statements

December 31, 2015 and 2014

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 12, 2016

"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, 2015 and 2014, and the consolidated statements of income, comprehensive income, cash flows and changes in equity for the years then ended, 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.

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. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes 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, 2015 and 2014, and its financial performance and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Halifax, Canada
February 12, 2016

"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 **2015**		2014
Operating revenues				
Regulated	**$**	**2,192.9**	$	2,113.1
Non-regulated		**596.4**		825.5
Total operating revenues		**2,789.3**		2,938.6
Operating expenses				
Regulated fuel for generation and purchased power		**814.5**		844.3
Regulated fuel adjustment mechanism and fixed cost deferrals (note 5)		**41.6**		46.6
Non-regulated fuel for generation and purchased power		**335.7**		401.1
Non-regulated direct costs		**19.5**		31.3
Operating, maintenance and general		**666.8**		560.8
Provincial, state, and municipal taxes		**63.6**		58.2
Depreciation and amortization		**339.9**		329.0
Total operating expenses		**2,281.6**		2,271.3
Income from operations		**507.7**		667.3
Income from equity investments (note 6)		**108.6**		66.6
Other income (expenses), net (note 7)		**141.1**		12.3
Interest expense, net (note 8)		**212.6**		179.8
Income before provision for income taxes		**544.8**		566.4
Income tax expense (recovery) (note 9)		**92.4**		113.6
Net income		**452.4**		452.8
Non-controlling interest in subsidiaries		**24.9**		19.9
Net income of Emera Incorporated		**427.5**		432.9
Preferred stock dividends		**30.3**		26.2
Net income attributable to common shareholders	**$**	**397.2**	$	406.7
Weighted average shares of common stock outstanding (in millions)				
Basic		**145.8**		143.2
Diluted		**146.4**		147.0
Earnings per common share (note 10)				
Basic	**$**	**2.72**	$	2.84
Diluted	**$**	**2.71**	$	2.82
Dividends per common share declared	**$**	**1.6625**	$	1.4750

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 **2015**	 2014
Net income	**$ 452.4**	$ 452.8
Other comprehensive income (loss), net of tax		
Foreign currency translation adjustment (1)	**434.6**	165.2
Cash flow hedges		
Net derivative gains (losses) (2)	**(33.5)**	(7.7)
Less: reclassification adjustment for losses (gains) included in income (3)	**6.5**	3.6
Net effects of cash flow hedges	**(27.0)**	(4.1)
Unrealized gains on available-for-sale investment		
Unrealized gain (loss) arising during the period	**(2.6)**	0.2
Net unrealized holding gains (losses)	**(2.6)**	0.2
Net change in unrecognized pension and post-retirement benefit obligation (4)	**107.1**	(71.3)
Other comprehensive income (loss) (5)	**512.1**	90.0
Comprehensive income (loss)	**964.5**	542.8
Comprehensive income (loss) attributable to non-controlling interest	**52.8**	31.6
Comprehensive Income of Emera Incorporated	**$ 911.7**	$ 511.2

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

1) Net of tax expense of $6.6 million (2014 - $2.3 million tax expense) for the year ended December 31, 2015.
2) Net of tax expense of $1.0 million (2014 - $3.7 million tax expense) for the year ended December 31, 2015.
3) Net of tax recovery of $1.7 million (2014 - $0.1 million tax recovery) for the year ended December 31, 2015.
4) Net of tax expense of $8.5 million (2014 - $13.6 million tax recovery) for the year ended December 31, 2015.
5) Net of tax expense of $14.4 million (2014 - $7.7 million tax recovery) for the year ended December 31, 2015.

Emera Incorporated
Consolidated Balance Sheets

As at				December 31
millions of Canadian dollars		**2015**		2014
Assets				
Current assets				
Cash and cash equivalents	**$**	**1,073.4**	$	221.1
Restricted cash (note 12)		**19.3**		15.9
Receivables, net (note 13)		**578.1**		514.2
Income taxes receivable		**12.1**		4.8
Inventory (note 14)		**314.3**		294.5
Derivative instruments (notes 15 and 16)		**249.5**		136.5
Regulatory assets (notes 5 and 17)		**94.2**		115.0
Prepaid expenses		**18.3**		24.7
Due from related parties (note 18)		**1.6**		3.5
Other current assets (note 19)		**234.8**		80.6
Total current assets		**2,595.6**		1,410.8
Property, plant and equipment, net of accumulated depreciation of $3,732.4 and $3,362.0, respectively (note 20)		**6,188.0**		5,610.2
Other assets				
Income taxes receivable		**48.7**		28.9
Deferred income taxes (note 9)		**32.2**		57.8
Derivative instruments (notes 15 and 16)		**167.6**		92.0
Pension and post-retirement asset (note 21)		**8.7**		5.9
Regulatory assets (notes 5 and 17)		**605.3**		487.7
Net investment in direct financing lease (note 22)		**480.1**		484.5
Investments subject to significant influence (note 6)		**1,145.3**		1,027.6
Available-for-sale investments (note 23)		**116.0**		84.4
Goodwill (note 24)		**264.1**		221.5
Intangibles, net of accumulated amortization of $92.8 and $88.3, respectively		**191.9**		134.3
Due from related parties (note 18)		**2.5**		2.5
Other long-term assets (note 25)		**166.3**		205.3
Total other assets		**3,228.7**		2,832.4
Total assets	**$**	**12,012.3**	$	9,853.4

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

Emera Incorporated
Consolidated Balance Sheets – Continued

As at		December 31
millions of Canadian dollars	**2015**	2014
Liabilities and Equity		
Current liabilities		
Short-term debt (note 26)	**$ 15.9**	$ 257.6
Current portion of long-term debt	**274.0**	94.5
Accounts payable	**394.2**	370.7
Income taxes payable	**8.1**	33.8
Convertible debentures represented by instalment receipts (note 30)	**727.6**	-
Derivative instruments (notes 15 and 16)	**349.2**	127.4
Regulatory liabilities (note 17)	**98.9**	43.0
Pension and post-retirement liabilities (note 21)	**7.0**	7.5
Due to related party (note 18)	**2.1**	1.6
Other current liabilities (note 27)	**204.3**	186.8
Total current liabilities	**2,081.3**	1,122.9
Long-term liabilities		
Long-term debt (note 28)	**3,750.8**	3,660.3
Deferred income taxes (note 9)	**761.7**	613.3
Derivative instruments (notes 15 and 16)	**96.1**	77.4
Regulatory liabilities (note 17)	**271.7**	158.9
Asset retirement obligations (note 29)	**114.7**	106.2
Pension and post-retirement liabilities (note 21)	**303.4**	360.7
Other long-term liabilities (note 31)	**298.5**	48.3
Total long-term liabilities	**5,596.9**	5,025.1
Commitments and contingencies (note 32)		
Equity		
Common stock, no par value, unlimited shares authorized, 147.21 million and 143.78 million shares issued and outstanding, respectively (note 33)	**2,157.5**	2,016.4
Cumulative preferred stock, Series A, B, C, E and F, par value $25 per share; unlimited shares authorized, 3.9 million, 2.1 million, 10 million, 5 million, and 8 million shares issued and outstanding, respectively (note 34)	**709.5**	709.5
Contributed surplus	**28.8**	8.8
Accumulated other comprehensive income (loss) (note 11)	**136.5**	(347.6)
Retained earnings	**1,167.8**	1,011.7
Total Emera Incorporated equity	**4,200.1**	3,398.8
Non-controlling interest in subsidiaries (note 35)	**134.0**	306.6
Total equity	**4,334.1**	3,705.4
Total liabilities and equity	**$ 12,012.3**	$ 9,853.4

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

Approved on behalf of the Board of Directors

"M. Jacqueline Sheppard" *"Christopher G. Huskilson"*

Chair of the Board **President and Chief Executive Officer**

Emera Incorporated
Consolidated Statements of Cash Flows

For the millions of Canadian dollars	Year ended December 31 **2015**	 2014
Operating activities		
Net income	**$ 452.4**	$ 452.8
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**352.2**	341.5
Income from equity investments, net of dividends	**(34.1)**	4.8
Allowance for equity funds used during construction	**(2.3)**	(9.5)
Deferred income taxes, net	**20.4**	39.9
Net change in pension and post-retirement liabilities	**37.3**	4.1
Regulated fuel adjustment mechanism and fixed cost deferrals	**38.8**	40.3
Net change in fair value of derivative instruments	**95.9**	(99.8)
Net change in regulatory assets and liabilities	**(6.3)**	(14.5)
Net change in capitalized transportation capacity	**(133.3)**	(40.3)
Unrealized foreign exchange gains	**(26.8)**	-
Other operating activities, net	**(18.4)**	(3.0)
Changes in non-cash working capital:		
Receivables, net	**(19.0)**	54.2
Income taxes receivable	**(21.6)**	(2.9)
Inventory	**(2.1)**	(41.8)
Prepaid expenses	**8.4**	0.9
Due from related party	**1.9**	(3.5)
Other current assets	**(1.6)**	(0.8)
Accounts payable	**(44.9)**	(0.1)
Income taxes payable	**(31.7)**	0.1
Other current liabilities	**9.0**	40.1
Net cash provided by operating activities	**674.2**	762.5
Investing activities		
Additions to property, plant and equipment	**(369.2)**	(433.7)
(Increase) decrease in restricted cash	**(0.7)**	7.4
Net purchase of investments subject to significant influence, inclusive of acquisition costs	**(136.1)**	(155.2)
Retirement spending, net of salvage	**(8.0)**	(7.5)
Purchase of subscription receipts	**-**	(110.5)
Proceeds on sale of investment subject to significant influence	**282.3**	-
Proceeds on distribution of investment subject to significant influence	**178.7**	-
Additions to intangible assets	**(58.0)**	(16.6)
Other investing activities	**(12.7)**	5.2
Net cash used in investing activities	**(123.7)**	(710.9)

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

Emera Incorporated
Consolidated Statements of Cash Flows – Continued

For the millions of Canadian dollars	Year ended December 31 **2015**	 2014
Financing activities		
Change in short-term debt, net	**(261.8)**	(214.3)
Proceeds from convertible debentures represented by instalment receipts, net of issuance costs (note 30)	**681.4**	-
Retirement of long-term debt	**(90.2)**	(308.9)
Proceeds from long-term debt	**446.5**	302.2
Net borrowings (repayments) under committed credit facilities	**(201.3)**	27.5
Issuance of common stock, net of issuance costs	**87.4**	310.0
Issuance of preferred stock, net of issuance costs	**-**	193.9
Dividends on common stock	**(240.4)**	(210.0)
Dividends on preferred stock	**(30.3)**	(26.2)
Dividends paid by subsidiaries to non-controlling interest	**(14.1)**	(13.5)
Redemption of preferred shares by subsidiary	**(135.0)**	-
Other financing activities	**(21.1)**	(2.5)
Net cash provided by financing activities	**221.1**	58.2
Effect of exchange rate changes on cash and cash equivalents	**80.7**	10.5
Net increase in cash and cash equivalents	**852.3**	120.3
Cash and cash equivalents, beginning of period	**221.1**	100.8
Cash and cash equivalents, end of period	**$ 1,073.4**	$ 221.1
Cash and cash equivalents consists of:		
Cash	**$ 995.8**	$ 160.2
Short-term investments	**77.6**	60.9
Cash and cash equivalents	**$ 1,073.4**	$ 221.1
Supplemental disclosure of cash paid (received):		
Interest	**$ 196.4**	$ 184.7
Income taxes	**$ 124.2**	$ 64.8

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 Income (“AOCI”)	Retained Earnings	Emera Total Equity	Non-Controlling Interest	Total Equity
2015								
Balance, December 31, 2014	$ 2,016.4	$ 709.5	$ 8.8	$ (347.6)	$ 1,011.7	$ 3,398.8	$ 306.6	$ 3,705.4
Net income of Emera Incorporated	-	-	-	-	427.5	427.5	24.9	452.4
Other comprehensive income (loss), net of tax expense of $14.4 million	-	-	-	484.2	-	484.2	27.9	512.1
Dividends declared on preferred stock (note 34)	-	-	-	-	(30.3)	(30.3)	-	(30.3)
Dividends declared on common stock ($1.6625/share)	-	-	-	-	(240.4)	(240.4)	-	(240.4)
Dividends paid and payable by subsidiaries to non-controlling interests	-	-	-	-	-	-	(3.1)	(3.1)
Common stock issued under purchase plan	84.2	-	-	-	-	84.2	-	84.2
Senior management stock options exercised	2.3	-	(0.2)	-	-	2.1	-	2.1
Stock option expense	-	-	1.5	-	-	1.5	-	1.5
Employee Share Purchase Plan	0.9	-	-	-	.	0.9	-	0.9
Preferred dividends paid and payable by subsidiaries to non-controlling interests	-	-	-	-	-	-	(11.9)	(11.9)
Redemption of preferred shares by subsidiary	-	-	-	-		-	(132.2)	(132.2)
Acquisition of non-controlling interest of ECI	53.7	-	18.9	-	-	72.6	(77.7)	(5.1)
Equity method investments	-	-	(0.2)	(0.1)	(0.7)	(1.0)	-	(1.0)
Other	-	-			-	-	(0.5)	(0.5)
Balance, December 31, 2015	$ 2,157.5	$ 709.5	$ 28.8	$ 136.5	$ 1,167.8	$ 4,200.1	$ 134.0	$ 4,334.1

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

Emera Incorporated
Consolidated Statements of Changes in Equity – Continued

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income ("AOCI")	Retained Earnings	Emera Total Equity	Non-Controlling Interest	Total Equity
2014								
Balance, December 31, 2013	$ 1,703.0	$ 514.0	$ 4.1	$ (430.1)	$ 817.2	2,608.2	$ 289.0	$ 2,897.2
Net income of Emera Incorporated	-	-	-	-	432.9	432.9	19.9	452.8
Other comprehensive income (loss), net of tax recovery of $7.7 million	-	-	-	78.3	-	78.3	11.7	90.0
Issuance of common stock, net of after-tax issuance costs	242.8	-	-	-	-	242.8	-	242.8
Dividends declared on preferred stock (note 34)	-	-	-	-	(26.2)	(26.2)	-	(26.2)
Dividends declared on common stock ($1.4750/share)	-	-	-	-	(210.0)	(210.0)	-	(210.0)
Dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	-	(2.3)	(2.3)
Issuance of preferred shares, net of after-tax issuance costs	-	195.5	-	-	-	195.5	-	195.5
Common stock issued under purchase plan	63.6	-	-	-	-	63.6	-	63.6
Senior management stock options exercised	6.2	-	(0.5)	-	-	5.7	-	5.7
Stock option expense	-	-	1.2	-	-	1.2	-	1.2
Employee Share Purchase Plan	0.8	-	-	-	-	0.8	-	0.8
Preferred dividends paid by subsidiaries to non-controlling interest	-	-	-	-	-	-	(10.7)	(10.7)
Equity method investments	-	-	4.0	4.2	(2.2)	6.0	-	6.0
Other	-	-	-	-	-	-	(1.0)	(1.0)
Balance, December 31, 2014	$ 2,016.4	$ 709.5	$ 8.8	$ (347.6)	$ 1,011.7	3,398.8	$ 306.6	$ 3,705.4

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

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 ("Emera" or the "Company") is an energy and services company which invests in electricity generation, transmission and distribution, as well as gas transmission and utility energy services.

Emera's primary rate-regulated subsidiaries and investments at December 31, 2015 included the following:

- Nova Scotia Power Inc. ("NSPI"), which is a fully integrated electric utility and the primary electricity supplier in Nova Scotia, serving approximately 506,000 customers;
- Emera Maine provides electric transmission and distribution services to approximately 158,000 customers in the State of Maine in the United States;
- a 95.5 per cent interest in Emera (Caribbean) Incorporated ("ECI"), the parent of The Barbados Light & Power Company Limited ("BLPC"), which is a vertically integrated utility and sole provider of electricity on the island of Barbados, serving approximately 126,000 customers; a 49.6 per cent indirect interest, through ECI's 51.9 per cent controlling interest, in Dominica Electricity Services Ltd. ("Domlec"), an integrated utility on the island of Dominica, serving approximately 36,000 customers; and a 18.2 per cent indirect interest, through ECI, in St. Lucia Electricity Services Limited ("Lucelec"), which is a vertically integrated regulated electric utility in St. Lucia;
- a 50.0 per cent direct and 30.4 per cent indirect interest (through a 60.7 per cent interest in ICD Utilities Limited ("ICDU")) in Grand Bahama Power Company Limited ("GBPC"), which is a vertically integrated utility and sole provider of electricity on Grand Bahama Island, serving approximately 19,000 customers;
- Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), which is a 145-kilometre pipeline delivering 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 Newfoundland & Labrador Holdings Inc. ("ENL"), focused on two transmission investments related to the development of an 824 megawatt ("MW") hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador, scheduled to be in service in 2017. ENL's two investments are:
    - 100 per cent interest in NSP Maritime Link Inc. ("NSPML"), which is developing the Maritime Link Project, a $1.56 billion transmission project, including two 170-kilometre sub-sea cables, between the island of Newfoundland and Nova Scotia;
    - 55.1 per cent investment in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.1 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Emera's percentage ownership in LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined on completion of the LIL and final costing of all transmission projects related to the Muskrat Falls development, including the LIL and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments. The investment in LIL is accounted for on the equity basis. This project is expected to go into service in 2017.
- a 12.9 per cent interest in Maritimes & Northeast Pipeline ("M&NP"), which is a 1,400-kilometre pipeline, which transports natural gas from offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States;

Emera Incorporated and its subsidiaries also own investments in other energy-related companies, including:

- Emera Energy Inc. (“Emera Energy”), includes:
    - Emera Energy Services (“EES”), a physical energy business that purchases and sells natural gas and electricity and provides related energy asset management services;
    - Bridgeport Energy, Tiverton Power and Rumford Power (“New England Gas Generating Facilities”), comprising 1,090 MW of combined-cycle gas-fired electricity generating capacity in the northeastern United States;
    - Bayside Power Limited Partnership (“Bayside Power”), which is a 290 MW electricity generating facility in Saint John, New Brunswick;
    - Brooklyn Power Corporation (“Brooklyn Energy”), which is a 30 MW biomass co-generation merchant electricity facility in Brooklyn, Nova Scotia. Brooklyn Energy has a long-term purchase power agreement with NSPI;
    - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC (“Bear Swamp”), which is a 600 MW pumped storage hydroelectric facility in northern Massachusetts;
    - a 49.0 per cent interest in Northeast Wind Partners II, LLC (“NWP”), a 419 MW portfolio of wind energy projects in the northeastern United States, which was sold on January 29, 2015;
- Emera Reinsurance Limited, which is a captive insurance company providing insurance and reinsurance to Emera and certain affiliates, to enable more cost efficient management of risk and deductible levels across Emera;
- Emera Utility Services Inc., which is a utility services contractor primarily operating in Atlantic Canada;
- Emera Utility Services (Bahamas) Limited (“EUS Bahamas”) provides utility construction services and plant operation services in The Bahamas;
- a 23.4 per cent investment in Algonquin Power & Utilities Corp. (“APUC”), which is a public company traded on the Toronto Stock Exchange under the symbol “AQN”;
- a 3.3 per cent investment in OpenHydro Group Ltd. (“Open Hydro”);
- and other investments.

Pending acquisition

On September 4, 2015, Emera entered into an Agreement and Plan of Merger pursuant to which, Emera US Inc., a wholly owned indirect subsidiary of Emera, will merge with and into TECO Energy, Inc. (“TECO Energy”), and TECO Energy will survive the merger and become a wholly owned indirect subsidiary of Emera. TECO Energy shareholders will receive $27.55 USD per common share in cash, which represents an aggregate purchase price of approximately $10.4 billion USD, when including assumption of approximately $3.9 billion USD of debt.

The closing of the acquisition, which is expected to occur mid-2016, is subject to certain regulatory and government approvals, including approval by the New Mexico Public Regulation Commission, the Committee on Foreign Investment in the United States, and the satisfaction of closing conditions. TECO Energy shareholder approval was received on December 3, 2015. On December 14, 2015, the New Mexico Public Regulation Commission established hearing to begin May 23, 2016 for the joint application for approval of the change in control of New Mexico Gas Co. effected by the Transaction. On January 21, 2016, the FERC approved the Transaction. On February 8, 2016, the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, waiting period expired.

TECO Energy is an energy-related holding company with regulated electric and gas utilities in Florida and New Mexico. TECO Energy’s holdings include: Tampa Electric, an integrated regulated electric utility which serves more than 700,000 customers in West Central Florida; Peoples Gas System, a regulated gas distribution utility which serves more than 350,000 customers across Florida; and New Mexico Gas

Co., also a regulated gas distribution utility which serves more than 510,000 customers across New Mexico.

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, as discussed in Note 37. Inter-company balances and inter-company transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate-regulated entities, is recorded in non-regulated operating revenues, with an offset to property, plant and equipment, regulated fuel for generation and purchased power, or operating, maintenance and general, depending on the nature of the transaction.

D. Use of Management Estimates

The preparation of consolidated financial statements in accordance with United States 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 ongoing 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, capitalized overhead, 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 for recovery either because the Company received specific approval from the appropriate regulator, or due to regulatory precedent established 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 AOCI.

G. Revenue Recognition

Operating revenues are recognized when electricity is delivered to customers or when products are delivered and services are rendered. Regulated 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.

Non-regulated revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured.

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. 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 in income.

I. 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 AOCI.

J. 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.

K. Cash and Cash Equivalents

Cash equivalents consist of highly liquid short-term investments with original maturities of three months or less at acquisition. Total short-term investments of $77.6 million have an effective interest rate of 0.6 per cent at December 31, 2015 (2014 – $60.9 million with an effective interest rate of 1.0 per cent).

L. 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.

M. Inventory

Fuel and materials inventory are measured at the lower of cost or market. Fuel costs are determined using the weighted average method and material costs are 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.

Emission credits inventory are measured using the first-in-first-out method. Emission credits inventory is recognized in inventory when purchased, or allocated by the respective government agency.

N. 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 major maintenance project increases the life or value of the underlying asset, the cost is capitalized.

O. 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, procurement, and fleet operating and maintenance. Expenditures for project development are capitalized if they are expected to have future economic benefit.

P. 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 require the appropriate regulatory approval.

Q. Intangible Assets

Intangible assets consist primarily of computer software, 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 asset in each category. The service lives of regulated intangible assets 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 15
Land rights	50 to 143
Naming rights	1 to 24

The estimated average amortization for each of the next five fiscal years is as follows:

millions of Canadian dollars	2016	2017	2018	2019	2020
Computer software	$ 12.1	$ 11.9	$ 11.6	$ 11.3	$ 11.9
Land rights	2.0	2.0	2.0	2.0	2.0
Naming rights	0.4	0.2	0.2	0.2	0.2
	$ 14.5	$ 14.1	$ 13.8	$ 13.5	$ 14.1

R. Asset Impairment

Goodwill

Goodwill is not amortized, but is subject to an annual impairment test. Emera's reporting units containing goodwill assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount during the fourth quarter of each year, and interim impairment tests are performed when impairment indicators are present. If it is more likely than not that a reporting unit's fair value is less than its carrying amount, the Company calculates the fair value of the reporting unit. 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 per cent likelihood that the indefinite-lived intangible asset's fair value is less than its carrying 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.

Cost and Equity Method Investments

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 in earnings equal to the amount the carrying value exceeds the investment's fair value.

Financial Assets

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 AOCI and recognized on the Consolidated Statements of Income.

S. Debt Financing Costs

The Company capitalizes the external costs of obtaining debt financing and includes them as "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.

T. 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 Consolidated Balance Sheets 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 Emera Maine 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, unless specifically directed otherwise by a regulator.

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

U. Asset Retirement Obligations

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

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation using the Company's credit adjusted risk-free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. Accretion expense is included as part of "Depreciation and amortization". Any regulated 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.

V. Derivatives and Hedging Activities

Emera's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management policies and practices are overseen by the Board of Directors. The Company has established a number of processes and practices to identify, monitor, report on and mitigate material risks to the Company. This includes establishment of the Enterprise Risk Management Committee, whose responsibilities include preparing and updating a "Risk Dashboard" for the Board of Directors on a quarterly basis. Furthermore, a corporate team independent from operations is responsible for tracking and reporting on market and credit risks.

The Company manages its exposure to normal operating and market risks relating to commodity prices, foreign exchange and interest rates through contractual protections with counterparties where practicable, and by 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 creditworthy. Emera continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exemption 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 AOCI 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 and GBPC that are documented as economic hedges, and for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. 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.

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. Transportation capacity arising as a result of trading and marketing transactions is recognized as an asset in "Other" and amortized over the period of the transportation contract term. 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. Non-hedged derivatives are included in operating cash flows on the Consolidated Statements of Cash Flows.

W. 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".

X. 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.

Y. 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 consolidated in the Company's consolidated financial statements.

Z. 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 AOCI 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”.

2. CHANGE IN ACCOUNTING POLICY

Business Combinations – Simplifying the Accounting for Measurement-Period Adjustments, Accounting Standard Update (“ASU”) Number (“No.”) 2015-16

In September 2015, the Financial Accounting Standards Board (“FASB”) issued ASU 2015-16, Business Combinations – *Simplifying the Accounting for Measurement-Period Adjustments*. The amendment applies to entities that have reported provisional amounts related to a business combination for which the accounting is incomplete by the end of the reporting period and have an adjustment to provisional amounts previously recognized during a later measurement period. Changes in provisional amounts recorded for acquired assets and liabilities are to be adjusted in the period the adjustment is known, with a corresponding adjustment booked to goodwill. The acquirer is no longer required to revise comparative information from prior years for the effect of changes in provisional amounts. The Company has adopted ASU 2015-16 effective Q3 2015, with no impact on the consolidated financial statements as a result of implementation of this standard.

Income Taxes – Balance Sheet Classification of Deferred Taxes, ASU 2015-17

In November 2015, the FASB issued ASU 2015-17*, Income Taxes – Balance Sheet Classification of Deferred Taxes,* which simplifies the presentation of deferred income taxes. The amendment requires that deferred tax assets and liabilities be classified as noncurrent on the Consolidated Balance Sheets, regardless of whether the deferred income taxes are expected to be recovered or settled within the next twelve months. ASU-2015-17 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. Early adoption is permitted for any interim or annual financial statements that have not yet been issued.

The Company has early adopted ASU 2015-17 effective December 31, 2015, and 2014 balances have been retrospectively restated. This change decreased the current deferred income tax asset and liability by $49.2 million and $4.1 million respectively on the Consolidated Balance Sheets as at December 31, 2015 (2014 – $27.9 million and $15.7 million respectively). As a result of the change the long-term deferred income tax asset increased by $15.2 million (2014 – $24.1 million) and the long-term deferred income tax liability decreased by $29.9 million (2014 – increased by $11.9 million) on the Consolidated Balance Sheets as at December 31, 2015.

This change also reclassified a $11.9 million current deferred income tax regulatory liability (2014 – $8.0 million) to the long-term deferred income tax regulatory asset on the Consolidated Balance Sheets as at December 31, 2015.

Fair Value Measurement Disclosures for Investments in Certain Entities That Calculate Net Asset Value (“NAV”) per Share (or Its Equivalent), ASU No. 2015-07

In May 2015, the FASB issued ASU 2015-07 removing the requirement to categorize and disclose, within the fair value hierarchy, all investments for which fair value is measured using the net asset value per share as a practical expedient. The Company has early adopted ASU No. 2015-07 effective December 31, 2015 and 2014. The adoption of this update resulted in disclosure of all investments for which fair value is measured using the net asset value per share methodology being disclosed outside of the fair-value hierarchy. As at December 31, 2015, total investments measured using the net asset value per share were $672.4 million (December 31, 2014 - $635.7 million).

3. FUTURE ACCOUNTING PRONOUNCEMENTS

Revenue from Contracts with Customers, ASU No. 2014-09
In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers,* which creates a new, principle-based revenue recognition framework and a new topic in the Accounting Standards Codification ("ASC"), Topic 606. ASC 606 also changes the basis for determining when revenue is recognized over time or at a point in time, provides new and more detailed guidance on specific aspects of revenue recognition and expands revenue disclosures. On July 9, 2015, the FASB deferred the effective date by one year. This standard will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

Income Statement – Extraordinary and Unusual Items, ASU No. 2015-01
In January 2015, the FASB issued ASU 2015-01, *Income Statement – Extraordinary and Unusual Items,* which simplifies the income statement presentation requirements by eliminating the concept of extraordinary items. ASU No. 2015-01 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

Consolidation, ASU No. 2015-02
In February 2015, the FASB issued ASU 2015-02, *Consolidation,* which changes the analysis a reporting entity must perform to determine whether it should consolidate certain types of legal entities. All legal entities are subject to re-evaluation under the revised consolidation model. ASU No. 2015-02 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

Interest – Imputation of Interest, No. ASU 2015-03
In April 2015, the FASB issued ASU 2015-03, Interest – *Imputation of Interest*, which simplifies the presentation of debt issuance costs. The amendments require debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs is not affected by the amendments in the update. ASU No. 2015-03 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2015. The adoption of this update will result in the reclassification of debt issuance costs from "Other long-term assets" to "Long-term debt" and "Convertible debentures represented by instalment receipts" on the Company's consolidated balance sheets. As at December 31, 2015, debt issuance costs included in "Other long-term assets were $66.8 million (December 31, 2014 - $18.8 million).

In August 2015, the FASB issued ASU 2015-15, *Interest – Imputation of Interest – Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*, which clarifies that the guidance in ASU No. 2015-03 does not apply to line-of-credit arrangements. ASU No. 2015-15 permits an entity to defer and present debt issuance costs as an asset and subsequently amortize these costs ratably over the time of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. ASU No. 2015-15 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2015. As at December 31, 2015, debt issuance costs associated with line-of-credit arrangements included in "Other long-term assets" were $4.0 million (December 31, 2014 - $4.1 million) on the Company's Consolidated Balance Sheets.

Compensation – Retirement Benefits, ASU No. 2015-04
In April 2015, the FASB issued ASU 2015-04, *Compensation – Retirement Benefits,* which is part of FASB's initiative to reduce complexity in accounting standards. This standard provides certain practical expedients for defined benefit pension or other post-retirement benefit plan measurement dates. ASU No. 2015-04 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

Intangibles – Goodwill and Other – Internal-Use Software, ASU No. 2015-05
In April 2015, the FASB issued ASU 2015-05, *Intangibles* **–** *Goodwill and Other* **–** *Internal-Use Software,* which provides guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, then the customer should account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer should account for the arrangement as a service contract. The guidance will not change GAAP for a customer's accounting for service contracts. ASU No. 2015-05 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

Technical Corrections and Improvements, ASU No. 2015-10
In June 2015, the FASB issued ASU 2015-10, *Technical Corrections and Improvements*, covering a wide range of topics in the codification to correct unintended application of guidance, or make minor improvements to the Codification that are not expected to have a significant effect on current accounting practice or create a significant administrative cost. ASU No. 2015-10 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

Inventory – Simplifying the Measurement of Inventory, ASU No. 2015-11
In July 2015, the FASB issued ASU 2015-11, Inventory – *Simplifying the Measurement of Inventory*. The amendments require an entity to measure inventory at the lower of cost or net realizable value, whereas previously, inventory was measured at the lower of cost or market. ASU No. 2015-11 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities, ASU No. 2016-01
In January 2016, the FASB issued ASU 2016-01, Financial Instruments – *Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. ASU No. 2016-01 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated 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 attributable to common shareholders and total assets.

As at December 31, 2015, Emera has six reportable segments, specifically:

- NSPI;
- Emera Maine;
- Emera Caribbean (ECI and its subsidiaries including BLPC, Domlec, GBPC, EUS Bahamas and an equity investment in Lucelec);
- Pipelines (Brunswick Pipeline and an equity investment in M&NP);
- Emera Energy (Emera Energy Services, New England Gas Generating Facilities, Bayside Power, Brooklyn Energy, equity investments in Bear Swamp and NWP for January 1, 2015 to January 29, 2015, when Emera sold its interest in NWP); and
- Corporate and Other (Emera Utility Services, ENL, Corporate, other strategic investments (including APUC) and holding companies.

millions of Canadian dollars	NSPI	Emera Maine	Emera Caribbean	Pipelines	Emera Energy	Corporate and Other	Inter-segment Eliminations	Total
For the year ended December 31, 2015								
Operating revenues from external customers (1)	**$ 1,417.3**	**$ 284.1**	**$ 442.5**	**$ 52.1**	**$ 578.0**	**$ 16.1**	**$ (2.4)**	**$ 2,787.7**
Inter-segment revenues (1)	**-**	**-**	**7.5**	**-**	**11.9**	**24.0**	**(41.8)**	**1.6**
Total operating revenues	**1,417.3**	**284.1**	**450.0**	**52.1**	**589.9**	**40.1**	**(44.2)**	**2,789.3**
Allowance for funds used during construction - debt and equity	**4.5**	**1.6**	**0.1**	**-**	**-**	**-**	**-**	**6.2**
Regulated fuel and fixed cost deferral adjustments	**41.6**	**-**	**-**	**-**	**-**	**-**	**-**	**41.6**
Depreciation and amortization	**206.5**	**46.6**	**44.1**	**0.4**	**40.6**	**1.7**	**-**	**339.9**
Interest expense	**119.6**	**18.8**	**14.0**	**9.7**	**0.7**	**47.7**	**-**	**210.5**
Interest revenue	**4.8**	**0.4**	**-**	**-**	**0.7**	**0.1**	**-**	**6.0**
Internally allocated interest (2)	**-**	**-**	**-**	**(16.5)**	**(17.7)**	**34.2**	**-**	**-**
Income from equity investments	**-**	**0.5**	**3.1**	**23.0**	**20.7**	**61.3**	**-**	**108.6**
Income tax expense (recovery)	**23.4**	**26.7**	**3.3**	**11.2**	**49.5**	**(21.7)**	**-**	**92.4**
Capital expenditures	**270.6**	**64.6**	**44.0**	**-**	**98.0**	**9.5**	**-**	**486.7**
Net income attributable to common shareholders	**129.9**	**45.1**	**40.5**	**37.5**	**98.9**	**45.3**	**-**	**397.2**
As at December 31, 2015							**-**	
Total assets	**4,641.6**	**1,559.8**	**1,406.8**	**804.5**	**1,918.5**	**1,906.4**	**(225.3)**	**12,012.3**
Investments subject to significant influence	**-**	**12.7**	**39.4**	**188.7**	**-**	**904.5**	**-**	**1,145.3**
Goodwill	**-**	**158.2**	**105.5**	**-**	**-**	**0.4**	**-**	**264.1**
For the year ended December 31, 2014								
Operating revenues from external customers (1)	$ 1,348.2	$ 242.6	$ 477.1	$ 48.8	$ 789.4	$ 31.4	$ (3.1)	$ 2,934.4
Inter-segment revenues (1)	-	-	8.8	-	11.5	17.3	(33.4)	4.2
Total operating revenues	1,348.2	242.6	485.9	48.8	800.9	48.7	(36.5)	2,938.6
Allowance for funds used during construction - debt and equity	5.9	5.6	0.2	-	-	2.4	-	14.1
Regulated fuel and fixed cost deferral adjustments	46.6	-	-	-	-	-	-	46.6
Depreciation and amortization	204.0	47.9	36.8	0.3	37.7	2.3	-	329.0
Interest expense	112.1	14.4	12.8	-	6.3	30.6	-	176.2
Interest revenue	7.6	0.5	-	-	-	0.1	-	8.2
Internally allocated interest (2)	-	-	-	(26.0)	-	26.0	-	-
Gain on acquisition	-	-	2.8	-	-	-	-	2.8
Income from equity investments	-	0.4	2.4	18.4	(0.9)	46.3	-	66.6
Income tax expense (recovery)	19.7	19.5	3.1	8.4	83.5	(20.6)	-	113.6
Capital expenditures	274.1	79.2	29.4	0.5	63.0	7.3	-	453.5
Net income attributable to common shareholders	124.9	42.4	28.7	32.7	185.7	(7.7)	-	406.7
As at December 31, 2014								
Total assets	4,318.1	1,292.6	1,149.3	783.2	1,645.2	817.7	(152.7)	9,853.4
Investments subject to significant influence	-	7.6	31.7	171.8	237.1	579.4	-	1,027.6
Goodwill	-	132.7	88.4	-	-	0.4	-	221.5

(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. Inter-company transactions which have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.
(2) Segment net income is reported on a basis that includes internally allocated financing costs.

Geographical Information

Revenues (1):

For the millions of Canadian dollars	Year ended December 31 **2015**	 2014
Canada	**$ 1,546.1**	$ 1,510.9
United States	**785.7**	933.8
Barbados	**258.9**	306.2
The Bahamas	**154.3**	146.0
Dominica	**44.3**	41.7
	$ 2,789.3	$ 2,938.6

(1) Revenues are based on country of origin of the product or service sold

Property Plant and Equipment:

As at millions of Canadian dollars	**December 31 2015**	December 31 2014
Canada	**$ 3,482.4**	$ 3,397.6
United States	**1,946.6**	1,577.3
Barbados	**398.7**	332.4
The Bahamas	**298.6**	252.0
Dominica	**61.7**	50.9
	$ 6,188.0	$ 5,610.2

5. REGULATED FUEL ADJUSTMENT MECHANISM AND FIXED COST DEFERRALS

Regulated fuel adjustment mechanism and fixed cost deferrals over (under) recovery consists of the following:

For the millions of Canadian dollars	Year ended December 31 **2015**	 2014
Regulated fuel adjustment mechanism (see chart below)	**$ 31.9**	$ 6.4
Application of non-fuel revenues	**44.7**	40.2
Fixed cost deferral related to 2015 demand side management ("DSM")	**(35.0)**	-
	$ 41.6	$ 46.6

Regulated Fuel Adjustment Mechanism

The regulated fuel adjustment mechanism ("FAM") included in the Consolidated Statements of Income includes the effect of prudently incurred fuel for generation and purchased power and certain fuel related costs ("Fuel Costs") in both the current and 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; and
- The recovery from (rebate to) customers of under (over) recovered Fuel Costs from prior years.

The regulated fuel adjustment mechanism on the Consolidated Statements of Income consisted of the following:

For the millions of Canadian dollars		Year ended December 31 **2015**		2014
Over (Under) recovery of current period Fuel costs	**$**	**(24.1)**	$	1.3
Recovery from (rebate to) customers of prior years' Fuel costs		**56.0**		-
FAM audit disallowance		**-**		5.1
Regulated fuel adjustment mechanism	**$**	**31.9**	$	6.4

The deferred FAM amounts are recognized as a "Regulatory asset" or "Regulatory liability" on the Consolidated Balance Sheets. The FAM regulatory liability balance of $28.3 million is disclosed in Note 17 and includes associated interest that is recorded as "Interest expense, net" on the Consolidated Statements of Income.

Pursuant to the FAM Plan of Administration, NSPI's fuel costs are subject to independent audit. On January 20, 2015, the UARB disallowed $6.0 million of 2012 and 2013 fuel-related costs, which includes interest of $0.9 million. The disallowances resulted in a reduction in the amount of the FAM deferral as at December 31, 2014 and resulted in an after-tax impact to 2014 net income of $3.3 million.

On December 21, 2015, the UARB approved NSPI's setting of the 2016 base cost of fuel and its recovery of prior period unrecovered fuel related costs as submitted in NSPI's August and November 2015 filings. The recovery of these costs will begin January 1, 2016. The approved customer rates reset the base cost of fuel rate for 2016 and seek to recover $13.7 million of prior years' unrecovered Fuel Costs in 2016. This decision results in a combined average rate decrease for customers of approximately 1 per cent.

On December 18, 2015, the Electricity Plan Implementation (2015) Act (the "Electricity Plan Act") was enacted by the Province of Nova Scotia. The Electricity Plan Act requires NSPI to file a three-year rate plan for Fuel Costs in Q1 2016 and to file a three-year general rate application to change non-fuel rates by April 30, 2016, if required by NSPI. A primary goal of the Electricity Plan Act is to provide rate stability over those years. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates during this period will be deferred to a FAM regulatory asset or liability and recovered from or returned to customers subsequent to 2019.

The Electricity Plan Act also directs NSPI to apply non-fuel revenues in excess of NSPI's approved range of return in 2015 and 2016 to the FAM, which will be reserved to be applied in the 2017 to 2019 period. In addition, the financial benefit resulting from a change in the recognition of tax benefits for the South Canoe and Sable Wind Projects is to be reserved to be applied to the FAM in the 2017 to 2019 period. The exception to this direction is to apply a sufficient amount of non-fuel revenues to offset potential fuel related rate increases for certain customer classes in 2016 that would have been otherwise required. This amount totals $4.6 million. As a result, as at December 31, 2015, NSPI has deferred $4.6 million of excess non-fuel revenues to 2016 and $40.1 million of excess non-fuel revenues for the periods 2017 to 2019.

A settlement agreement, approved by the UARB in November 2014, resulted in approximately $56.0 million of the outstanding FAM balance as at December 31, 2014 being collected in 2015. The settlement agreement also reduced the FAM regulatory asset at the end of 2014 of $86.1 million by $38.2 million via an offset from the liability balance in the Rate Stabilization deferral account, such that at December 31, 2014 the FAM regulatory asset was $47.9 million.

Through a related settlement agreement with stakeholders in December 2014, NSPI agreed to apply non-fuel revenues above that required to achieve its approved range of return to reduce the FAM deferral account. This was effective as of January 1, 2015, and remains until the next General Rate Application ("GRA") approval or similar process where non-fuel rates are adjusted. This settlement agreement required NSPI to contribute a minimum of $41.3 million to the FAM deferral account by the end of 2015. As at December 31, 2015, NSPI had exceeded the minimum required contribution through the $38.2 million in 2014 referred to above and an additional $26.4 million in 2015. In 2015, NSPI applied $44.7

million in excess non-fuel revenues against the FAM; $18.3 million was the result of the change to South Canoe and Sable Wind Projects tax treatment.

Regulated Fixed Cost Deferrals

NSPI has the following regulatory assets arising from UARB approved fixed cost deferral mechanisms:

DSM Deferral

In April 2014, the Government of Nova Scotia announced new energy efficiency legislation to remove a previous charge for conservation and efficiency programs from power bills of Nova Scotia customers effective January 1, 2015. In addition, the legislation requires NSPI to purchase electricity efficiency and conservation activities ("Program Costs") from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. The Program Costs were set for 2015 at $35.0 million and have been deferred as a regulatory asset and recoverable from customers over an eight-year period beginning in 2016. In August 2015, the UARB approved a budget of $102.0 million for the three-year period of 2016 through 2018. The Electricity Plan Act has placed a cap of $34.0 million on the 2019 DSM spending. The 2016 DSM cost of $24.7 million will not be deferred. A decision of the timing of the cost recovery for 2017 through 2019 will be made at a future date.

The Program Costs are recorded in "OM&G", with an offsetting credit in "Regulated fuel adjustment mechanism and fixed cost deferrals" on Emera's Consolidated Income Statements, with no effect on net earnings, with the exception of interest on the balance.

The deferred DSM amounts are recognized as a "Regulatory asset" on the Consolidated Balance Sheets. The DSM regulatory asset balance of $36.4 million is disclosed in Note 17 and includes associated interest that is recorded as "Interest expense, net" on the Consolidated Statements of Income.

2013/2014 Rate Stabilization Fixed Cost Recovery Deferral

In December 2012, the UARB approved a deferral of recovery of certain fixed costs for fiscal 2013 and 2014 as part of a rate stabilization plan. As previously noted above under the Regulated Fuel Adjustment Mechanism, the resulting regulatory liability at the end of 2014 of $38.2 million was applied against the FAM regulatory asset balance in 2014 and is included in the application of non-fuel revenues line in the table above.

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
	2015	2014	**2015**	2014	**2015**
APUC (1) (2)	**$ 503.7**	**$** 336.4	**$ 36.9**	$ 30.4	**23.4**
LIL (3)	**208.1**	80.1	**9.5**	6.4	**55.1**
M&NP (4)	**188.7**	171.8	**23.0**	18.4	**12.9**
NSPML (5)	**187.6**	159.3	**14.9**	9.5	**100.0**
Lucelec (4)	**39.4**	31.7	**3.1**	2.4	**18.2**
Maine Electric Power Company Inc.	**7.0**	2.9	**0.5**	0.4	**21.7**
Chester Static Var Compensator	**5.3**	4.4	**-**	-	**50.0**
Cape Sharp Tidal Venture Ltd.	**5.1**	3.6	**-**	-	**20.0**
Maine Yankee Atomic Power Company (4)	**0.4**	0.3	**-**	-	**12.0**
Bear Swamp (6)	**-**	-	**16.4**	16.4	**50.0**
NWP (7)	**-**	237.1	**4.3**	(17.3)	**49.0**
	$ 1,145.3	$ 1,027.6	**$ 108.6**	$ 66.6	

(1) As at December 31, 2015, the market price/share was $10.91 (December 31, 2014 - $9.64), which indicates a fair market value of this investment of $684.5 million (December 31, 2014 – $483.2 million). Emera holds 50.1 million shares and 12.6 million outstanding subscription receipts and dividend equivalents as at December 31, 2015 at an average book value of $8.03 per share. Carrying value reflects a cash cost of $371.2 million, plus non-cash gains recognized on conversion of subscriptions receipts into common shares, dilution gains or losses, and equity income or loss, less dividends received. In Q4 2015, Emera reclassified outstanding subscription receipts from "Other long-term assets" to Investments subject to significant influence as they became eligible for conversion into APUC common shares.
(2) Emera's Strategic Investment Agreement with APUC and a ruling by the Maine Public Utilities ("MPUC") limits Emera's ownership in APUC to 25 per cent of APUC's voting securities. The MPUC also stipulated Emera's dollar investment in APUC cannot exceed 5 per cent of Emera's total assets. As at December 31, 2015, Emera is in compliance with both of these requirements.
(3) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.9 per cent of the total units issued. Emera's share of the total partnership capital is 55.1 per cent.
(4) Although Emera's ownership percentage of these entities is relatively low, it is considered to have significant influence over the operating and financial decisions of these companies through Board representation. Therefore, Emera records its investment in these entities using the equity method. This is consistent with industry practice for similar investments with significant influence.
(5) Until Emera achieved certain critical milestones, including its financing and approvals to enable it to proceed to full construction, Emera recorded the Maritime Link Project development and engineering costs in "Property, plant and equipment" on its Consolidated Balance Sheets. In Q2 2014, when the critical milestones were achieved, and Nalcor Energy was deemed the beneficiary of the asset for financial reporting purposes, Emera began recording the Maritime Link Project as an equity investment, with equity earnings equal to the return on equity component of AFUDC. This will continue until the Maritime Link Project goes into service, which is expected in 2017. At that time, Emera will record equity earnings equal to 100 per cent of NSPML net earnings.
(6) As at December 31, 2015 and 2014, the credit investment balance has been reclassified to "Other Long-term liabilities" on the Consolidated Balance Sheets. The 2015 and 2014 carrying value has been restated.
(7) On January 29, 2015, Emera completed the sale of its 49 per cent interest in NWP for proceeds of $282.3 million ($223.3 million USD).

Equity investments include a $145.0 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.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 37). NSPML's consolidated summarized balance sheet are illustrated as follows:

As at millions of Canadian dollars		**2015**		December 31 2014
Balance Sheet				
Current assets	**$**	**438.7**	$	388.4
Property, plant and equipment		**647.7**		319.3
Non-current assets		**565.6**		865.5
Total assets	**$**	**1,652.0**	$	1,573.2
Current liabilities	**$**	**129.8**	$	100.4
Non-current liabilities		**1,334.6**		1,313.5
Equity		**187.6**		159.3
Total liabilities and equity	**$**	**1,652.0**	$	1,573.2

Bear Swamp

As at December 31, 2015, the investment balance in Bear Swamp was a credit of $225.0 million (2014 – credit of $20.8 million). The credit investment balance is primarily a result of distributions received in excess of the original cost and earnings. This credit investment balance is recorded as a long-term liability on the Consolidated Balance Sheets (note 31).

On October 8, 2015, Bear Swamp refinanced its $125 million USD bank debt that was due to mature in 2017 and issued $400 million USD in senior secured 10-year bonds, with $375 million USD at a fixed rate of 4.89 per cent, and $25 million USD at a floating rate of LIBOR plus 2.70 per cent. The proceeds of this financing were used to repay existing debt and provide working capital to the joint venture, with the remainder shared equally between Emera and its joint venture partner. After fees and expenses, Emera received a $178.7 million ($137.3 million USD) non-taxable distribution in Q4 2015.

7. OTHER INCOME (EXPENSES), NET

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

For the millions of Canadian dollars		Year ended **2015**		December 31 2014
Foreign exchange gains (losses) and mark-to-market adjustments related to the pending TECO Energy acquisition	**$**	**118.9**	$	-
Gain on sale of NWP investment		**18.6**		-
Foreign exchange gains (losses) - Other		**3.8**		2.6
Allowance for equity funds used during construction		**2.3**		9.5
Investment income		**1.2**		1.6
Amortization of defeasance costs		**(6.7)**		(7.9)
Other		**3.0**		6.5
	$	**141.1**	$	12.3

8. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of Canadian dollars	Year ended December 31 **2015**	 2014
Interest on debt	**$ 192.8**	$ 186.2
Interest on convertible debentures represented by instalment receipts	**22.7**	-
Allowance for borrowed funds used during construction	**(3.9)**	(4.6)
Interest revenue	**(6.0)**	(8.2)
Other	**7.0**	6.4
	$ 212.6	$ 179.8

9. INCOME TAXES

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

millions of Canadian dollars	**2015**	2014
Income before provision for income taxes	**$ 544.8**	$ 566.4
Statutory income tax rate	**31.0%**	31.0%
Income taxes, at statutory income tax rates	**168.9**	175.6
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(31.3)**	(33.6)
Non-taxable portion of mark-to-market gains related to pending TECO Energy acquisition	**(18.4)**	-
Tax effect of equity earnings	**(11.3)**	(8.4)
Other	**(15.5)**	(20.0)
Income tax expense (recovery)	**$ 92.4**	$ 113.6
Effective income tax rate	**17.0%**	20.1%

The 2015 and 2014 statutory income tax rate of 31.0 per cent 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	**2015**	2014
Income tax expense (recovery) - current		
Domestic	**$ 41.3**	$ 56.4
Foreign	**30.7**	17.3
Income tax expense (recovery) - deferred		
Domestic	**(3.8)**	(16.7)
Foreign	**(81.7)**	55.3
Operating loss carry forwards		
Domestic	**10.5**	35.4
Foreign	**95.4**	(34.1)
Income tax expense (recovery)	**$ 92.4**	$ 113.6

The following reflects the composition of income before provision for income taxes for the years ended December 31, 2015.

millions of Canadian dollars	**2015**	2014
Domestic	**$ 349.1**	$ 390.9
Foreign	**195.7**	175.5
Income before provision for income taxes	**$ 544.8**	$ 566.4

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

millions of Canadian dollars		2015		2014
Deferred income tax assets:				
Derivative instruments	**$**	**191.5**	$	128.2
Pension and post-retirement liabilities		**128.9**		156.2
Regulatory liabilities		**106.7**		54.5
Tax loss carry forwards		**72.6**		161.0
Asset retirement obligations		**48.7**		45.5
Intangibles		**31.8**		36.4
Other		**98.0**		77.8
Total deferred income tax assets before valuation allowance		**678.2**		659.6
Valuation allowance		**(18.2)**		(19.2)
Total deferred income tax assets after valuation allowance	**$**	**660.0**	$	640.4
Deferred income tax liabilities:				
Property, plant and equipment	**$**	**920.0**	$	841.7
Derivative instruments		**251.2**		176.7
Net investment in direct financing lease		**88.4**		82.1
Other		**129.9**		95.4
Total deferred income tax liabilities	**$**	**1,389.5**	$	1,195.9
Consolidated Balance Sheets presentation:				
Long-term deferred income tax assets		**32.2**		57.8
Long-term deferred income tax liabilities		**(761.7)**		(613.3)
Net deferred income tax liabilities	**$**	**(729.5)**	$	(555.5)

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, unless specifically directed otherwise by a regulator. 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.

The following table summarizes as at December 31, 2015 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	$	54.0	$	(2.7)	$	51.3	2016 - 2035
Capital loss		18.6		(15.0)		3.6	2018-Indefinite
Tax credit		1.9		-		1.9	2028-Indefinite

As at December 31, 2015, Emera had a gross NOL carryover of $389.0 million (2014 - $1,074.1 million), capital loss carryover of $88.0 million (2014 - $79.1 million), and a tax credit carryover of $25.0 million (2014 - $4.4 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, 2015 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		**2015**		2014
Balance, January 1	**$**	**4.8**	$	5.2
Increases due to tax positions related to current year		**0.5**		0.1
Increases due to tax positions related to a prior year		**0.8**		1.7
Decreases due to tax positions related to a prior year		**-**		(1.2)
Decreases due to expiration of statute of limitations		**-**		(1.0)
Balance, December 31	**$**	**6.1**	$	4.8

The total amount of unrecognized tax benefits as at December 31, 2015 was $6.1 million (2014 - $4.8 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $0.6 million (2014 - $0.8 million). No penalties have been accrued. The balance in unrecognized tax benefits could change up to $4.9 million in the next twelve months as a result of settlements of Canada Revenue Agency ("CRA") audits of NSPI.

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 $669.4 million as at December 31, 2015 (2014 - $555.4 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, St. Lucia and Dominica income tax returns. As at December 31, 2015, the Company's tax years still open to examination by taxing authorities include 2006 and subsequent years.

NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for its 2006 through 2010 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is $62.3 million, including taxes and interest. NSPI has prepaid $22.7 million of the amount in dispute, as required by CRA.

Should NSPI be successful in defending its position, all payments including applicable interest will be refunded with respect to NSPI's deductions. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the excess, if any, owing to CRA. The related tax deductions will be available in subsequent years.

In Q2 2015, CRA commenced audit of NSPI's 2011 through 2013 taxation years. Should NSPI receive notices of reassessment for those years, and should the 2014 and 2015 taxation years be similarly reassessed, further payments will be required; however, the ultimate permissibility of the deductions is similarly not in dispute.

NSPI and its advisors believe that NSPI has reported its tax position appropriately and NSPI is disputing the reassessments through the CRA Appeal process. The outcome of this process is not determinable at this time.

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 **2015**	2014
Numerator		
Net income attributable to common shareholders	**$ 397.2**	$ 406.7
Preferred stock dividends of subsidiary (1)	**-**	7.7
Diluted numerator	**397.2**	414.4
Denominator		
Weighted average shares of common stock outstanding	**144.9**	142.4
Weighted average deferred share units outstanding	**0.9**	0.8
Weighted average shares of common stock outstanding – basic	**145.8**	143.2
Effect of dilutive securities (1)	**-**	3.5
Stock-based compensation	**0.6**	0.3
Weighted average shares of common stock outstanding – diluted	**146.4**	147.0
Earnings per common share		
Basic	**$ 2.72**	$ 2.84
Diluted (1)	**$ 2.71**	$ 2.82

(1) On October 15, 2015, NSPI redeemed all of its outstanding Cumulative Redeemable First Preferred Shares. Therefore, the preferred shares are excluded from the calculation of diluted earnings per share as at December 31, 2015.

Convertible Debentures Effect on EPS

Following the satisfaction of all conditions precedent to the closing of the acquisition of TECO Energy, at the option of holders and provided that payment of the final installment has been made, each Debenture will be convertible into common shares of Emera at any time after the Final Instalment Date, but prior to maturity or redemption by the Company at a conversion price of $41.85 per common share, being a conversion rate of 23.8949 common shares per $1,000 principal amount of Debentures (note 30). Accordingly, a total of approximately 52.2 million common shares could be issued to convert the Debentures into common shares. When the conditions for closing the acquisition are met, the Debentures will be included as a component of the Company's diluted EPS.

11. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of accumulated other comprehensive income are as follows:

millions of Canadian dollars	(Losses) gains on derivatives recognized as cash flow hedges	Net change in unrecognized pension and post-retirement benefit costs	Net change on available-for-sale investments	Unrealized (loss) gain on translation of self-sustaining foreign operations	Total AOCI
For the year ended December 31, 2015					
Balance, January 1, 2015	$ (7.9)	$ (424.7)	$ 2.6	$ 82.4	$ (347.6)
Other comprehensive income (loss) before reclassifications	(33.5)	-	(2.3)	406.5	370.7
Amounts reclassified from accumulated other comprehensive income loss	6.5	107.1	-	-	113.6
Net current period other comprehensive income (loss)	(27.0)	107.1	(2.3)	406.5	484.3
Other	(0.2)	-	-	-	(0.2)
Balance, December 31, 2015	$ (35.1)	$ (317.6)	$ 0.3	$ 488.9	$ 136.5

millions of Canadian dollars	(Losses) gains on derivatives recognized as cash flow hedges	Net change in unrecognized pension and post-retirement benefit costs	Net change on available-for-sale investments	Unrealized (loss) gain on translation of self-sustaining foreign operations	Total AOCI
For the year ended December 31, 2014					
Balance, January 1, 2014	$ (4.2)	$ (353.4)	$ 2.4	$ (74.9)	$ (430.1)
Other comprehensive income (loss) before reclassifications	(7.7)	-	0.2	153.5	146.0
Amounts reclassified from accumulated other comprehensive income loss (gain)	3.6	(71.3)	-	-	(67.7)
Net current period other comprehensive income (loss)	(4.1)	(71.3)	0.2	153.5	78.3
Other	0.4	-	-	3.8	4.2
Balance, December 31, 2014	$ (7.9)	$ (424.7)	$ 2.6	$ 82.4	$ (347.6)

The reclassifications out of accumulated other comprehensive income (loss) are as follows:

For the		Year ended December 31	
millions of Canadian dollars		**2015**	2014
	Affected line item in the Consolidated Statements of Income	Amounts reclassified from AOCI	
Losses (gain) on derivatives recognized as cash flow hedges			
Power and gas swaps	Non-regulated fuel for generation and purchased power	$ **(4.8)**	$ (0.9)
Interest rate swaps	Income from equity investments	**0.6**	0.5
Interest rate swaps	Interest expense, net	**-**	0.2
Foreign exchange forwards	Operating revenue - regulated	**9.0**	3.7
Total before tax		**4.8**	3.5
	Income tax expense	**1.7**	0.1
Total net of tax		$ **6.5**	$ 3.6
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial losses (gains)	OM&G	$ **50.4**	$ 33.4
Past service costs (gains)	OM&G	**(7.1)**	(2.5)
Amounts reclassified into obligations	Pension and post-retirement benefits	**72.3**	(115.8)
Total before tax		**115.6**	(84.9)
	Income tax expense (recovery)	**(8.5)**	13.6
Total net of tax		$ **107.1**	$ (71.3)
Total reclassifications out of AOCI, net of tax, for the period		$ **113.6**	$ (67.7)

12. RESTRICTED CASH

Restricted cash consisted of the following:

As at millions of Canadian dollars	**December 31 2015**	December 31 2014
Restricted cash – BLPC	**$ 14.8**	$ 14.9
Restricted cash – Brunswick Pipeline	**3.4**	-
Restricted cash – Other	**1.1**	1.0
	$ 19.3	$ 15.9

13. RECEIVABLES, NET

Receivables, net consisted of the following:

As at millions of Canadian dollars	**December 31 2015**	December 31 2014
Customer accounts receivable – billed	**$ 407.0**	$ 356.0
Customer accounts receivable – unbilled	**144.2**	141.1
Total customer accounts receivable	**551.2**	497.1
Allowance for doubtful accounts	**(12.6)**	(11.1)
Customer accounts receivable, net	**538.6**	486.0
Other	**39.5**	28.2
	$ 578.1	$ 514.2

14. INVENTORY

Inventory consisted of the following:

As at millions of Canadian dollars		**December 31 2015**		December 31 2014
Fuel	**$**	**185.3**	$	185.7
Materials		**100.4**		87.9
Emission credits (1)		**28.6**		20.9
	$	**314.3**	$	294.5

(1)The New England Gas Generating Facilities are subject to the Acid Rain Program for sulphur dioxide emissions and the Regional Greenhouse Gas Initiative ("RGGI") for carbon dioxide emissions. In addition, Bridgeport Energy is subject to the Clean Air Interstate Rule for ozone season nitrogen dioxide emission allowances. The emissions credits inventory balance represents the credits purchased to offset the liabilities (note 31) associated with these programs.

15. DERIVATIVE INSTRUMENTS

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

	Derivative Assets		Derivative Liabilities	
As at	December 31		December 31	
millions of Canadian dollars	**2015**	2014	**2015**	2014
Current				
Cash flow hedges				
Power swaps	**$ 7.9**	$ 8.4	**$ 0.5**	$ 0.5
Foreign exchange forwards	**-**	0.1	**14.4**	4.5
	7.9	8.5	**14.9**	5.0
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	-	**11.7**	5.4
Natural gas purchases and sales	**1.5**	0.8	**0.7**	1.4
Heavy fuel oil purchases	**-**	-	**20.5**	12.6
Foreign exchange forwards	**85.3**	36.0	**10.5**	-
Physical natural gas purchases and sales	**1.8**	0.1	**-**	-
	88.6	36.9	**43.4**	19.4
HFT derivatives				
Power swaps and physical contracts	**150.8**	138.1	**118.5**	74.1
Foreign exchange options	**98.6**	-	**2.1**	-
Natural gas swaps, futures, forwards, physical contracts	**-**	86.4	**358.8**	162.3
	249.4	224.5	**479.4**	236.4
Other derivatives				
Foreign exchange forwards	**92.1**	-	**-**	-
	92.1	-	**-**	-
Total gross current derivatives	**438.0**	269.9	**537.7**	260.8
Impact of master netting agreements with intent to settle net or simultaneously	**(188.5)**	(133.4)	**(188.5)**	(133.4)
Total current derivatives	**249.5**	136.5	**349.2**	127.4
Long-term				
Cash flow hedges				
Power swaps	**11.6**	14.5	**4.1**	3.7
Foreign exchange forwards	**0.3**	-	**27.2**	10.5
	11.9	14.5	**31.3**	14.2
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	-	**4.4**	4.8
Heavy fuel oil purchases	**-**	-	**16.6**	12.9
Foreign exchange forwards	**121.4**	61.5	**-**	3.9
	121.4	61.5	**21.0**	21.6
HFT derivatives				
Power swaps and physical contracts	**12.9**	18.5	**28.2**	22.2
Natural gas swaps, futures, forwards and physical contracts	**72.3**	31.7	**62.6**	53.6
Foreign exchange options	**0.4**	-	**1.4**	-
	85.6	50.2	**92.2**	75.8
Other derivatives				
Interest rate swap	**-**	-	**2.9**	-
	-	-	**2.9**	-
Total gross long-term derivatives	**218.9**	126.2	**147.4**	111.6
Impact of master netting agreements with intent to settle net or simultaneously	**(51.3)**	(34.2)	**(51.3)**	(34.2)
Total long-term derivatives	**167.6**	92.0	**96.1**	77.4
Total derivatives	**$ 417.1**	$ 228.5	**$ 445.3**	$ 204.8

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

Details of master netting agreements, shown net on the Consolidated Balance Sheets, are summarized in the following table:

	Derivative Assets		Derivative Liabilities	
As at	December 31		December 31	
millions of Canadian dollars	**2015**	2014	**2015**	2014
Regulatory deferral	**$ 0.1**	$ 0.7	**$ 0.1**	$ 0.7
HFT derivatives	**239.7**	166.9	**239.7**	166.9
Total impact of master netting agreements with intent to settle net or simultaneously	**$ 239.8**	$ 167.6	**$ 239.8**	$ 167.6

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. Emera also enters into interest rate swaps to fix Bear Swamp's cost of debt. The Company also enters into foreign exchange forwards to hedge the currency risk for revenue streams denominated in foreign currency for Brunswick Pipeline.

As previously noted, the effective portion of the change in fair value of these derivatives is included in AOCI, 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 AOCI consisted of the following:

For the				Year ended December 31		
millions of Canadian dollars			**2015**			2014
	Power swaps	**Interest rate swaps**	**Foreign exchange forwards**	Power swaps	Interest rate swaps	Foreign exchange forwards
Unrealized gain (loss) in non-regulated fuel for generation and purchased power – ineffective portion	**$ (0.1)**	**$ -**	**$ -**	$ 2.7	$ -	$ -
Realized gain (loss) in non-regulated fuel for generation and purchased power	**4.8**	**-**	**-**	0.9	-	-
Realized gain (loss) in operating revenue – Regulated	**-**	**-**	**(9.0)**	-	-	(3.7)
Realized gain (loss) in income from equity investments	**-**	**(0.6)**	**-**	-	(0.5)	-
Realized gain (loss) in interest expense, net	**-**	**-**	**-**	-	(0.2)	-
Total gains (losses) in Net income	**$ 4.7**	**$ (0.6)**	**$ (9.0)**	$ 3.6	$ (0.7)	$ (3.7)

As at				December 31		
millions of Canadian dollars			**2015**			2014
	Power swaps	**Interest rate swaps**	**Foreign exchange forwards**	Power swaps	Interest rate swaps	Foreign exchange forwards
Total unrealized gain (loss) in AOCI – effective portion, net of tax	**$ 3.5**	**$ (1.1)**	**$ (41.7)**	$ 5.2	$ (1.4)	$ (14.9)

The Company expects $13.3 million of unrealized losses currently in AOCI to be reclassified into net income within the next twelve months, as the underlying hedged transactions settle.

As at December 31, 2015, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions		2016		2017		2018		2019		2020
Power swaps (megawatt hours ("MWh")) purchases		**0.3**		0.3		0.3		0.3		0.3
Foreign exchange forwards (USD) sales	$	**53.4**	$	53.4	$	44.8	$	30.0	$	30.0
Foreign exchange forwards (EURO) purchases		**-**		2.6		-		-		-

Regulatory Deferral

As previously noted, NSPI and GBPC defer 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 changes in realized and unrealized gains (losses) with respect to derivatives receiving regulatory deferral:

For the millions of Canadian dollars			**2015**			Year ended December 31 2014
	Commodity swaps and forwards	**Physical natural gas purchases and sales**	**Foreign exchange forwards**	Commodity swaps and forwards	Physical natural gas purchases and sales	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ (24.0)**	**$ -**	**$ (7.0)**	$ 14.3	$ -	$ (4.6)
Unrealized gain (loss) in regulatory liabilities	**1.4**	**8.8**	**172.7**	7.8	2.4	75.9
Realized (gain) loss in regulatory assets	**(3.3)**	**-**	**-**	3.3	-	-
Realized (gain) loss in property, plant and equipment	**-**	**-**	**(1.0)**	-	-	(0.1)
Realized (gain) loss in inventory (1)	**11.5**	**-**	**(43.9)**	4.3	-	(16.3)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(15.9)**	**(7.1)**	**(18.2)**	(9.7)	(2.3)	(5.7)
Total change derivative instruments	**$ (30.3)**	**$ 1.7**	**$ 102.6**	$ 20.0	$ 0.1	$ 49.2

(1) Realized (gains) losses will be recognized in fuel for generation and purchased power when the hedged item is consumed.

(2) Realized (gains) losses on derivative instruments settled and consumed in the period; hedging relationships that have been terminated or the hedged transaction is no longer probable.

Commodity Swaps and Forwards

As at December 31, 2015, 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:

	2016	2017	2018
millions	**Purchases**	Purchases	Purchases
Coal (metric tonnes)	**0.3**	0.7	0.7
Natural Gas (mmbtu)	**3.2**	-	-
Heavy fuel oil (bbls)	**0.4**	0.2	0.1

Foreign Exchange Swaps and Forwards

As at December 31, 2015, the Company had the following notional volumes of foreign exchange swaps and forward contracts related to commodity contracts that are expected to settle as outlined below:

	2016	2017	2018	2019
Fuel purchases exposure (millions of US dollars)	$ 200.4	$ 222.3	$ 143.0	$ 96.5
Weighted average rate	1.0257	1.0707	1.1053	1.1265
% of USD requirements	79%	93%	68%	46%

Held-for-Trading Derivatives

In the ordinary course of its business, Emera enters into physical contracts for the purchase and sale of natural gas, as well as 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 **2015**	2014
Power swaps and physical contracts in non-regulated operating revenues	**$ 9.8**	$ 6.4
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**4.6**	264.0
Natural gas swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**(3.1)**	(5.2)
Foreign exchange options in other income (expenses), net	**(0.8)**	-
	$ 10.5	$ 265.2

As at December 31, 2015, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	**2016**	2017	2018	2019	2020
Natural gas purchases (Mmbtu)	**211.3**	65.5	49.9	43.9	43.9
Natural gas sales (Mmbtu)	**151.0**	35.1	5.4	5.1	4.4
Power purchases (MWh)	**1.6**	0.6	0.6	0.6	0.6
Power sales (MWh)	**2.7**	-	-	-	-
Foreign exchange options (USD)	**$ 20.3**	$ 12.5	$ 4.1	-	-
Foreign exchange forwards (EURO) purchases	**-**	-	0.2	-	-

Other Derivatives

The Company has recognized the following realized and unrealized gains (losses) with respect to cash flow hedges which documentation requirements have not been met:

For the millions of Canadian dollars		**2015**	Year ended December 31	2014
	Interest rate swaps	**Foreign exchange forwards**	Interest rate swaps	Foreign exchange forwards
Unrealized gain (loss) in other income (expense)	**$**	**$ 92.1**	$ -	$ -
Unrealized gain (loss) in interest expense, net	**(2.9)**	**-**	-	-
Total gains (losses) in net income	**$ (2.9)**	**$ 92.1**	**$ -**	**$ -**

As at December 31, 2015, the Company had interest rate swaps in place for the $250 million non-revolving term credit facility in Brunswick Pipeline for interest payments until the debt matures in 2019.

As at December 31, 2015, the Company had a foreign exchange forwards in place for $1,121.7 million USD in 2016 to economically hedge the anticipated proceeds from the Debenture Offering for the pending TECO Energy acquisition.

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 a 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, 2015, the maximum exposure the Company has to credit risk is $901.0 million (2014 - $707.3 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, 2015 was $94.2 million (2014 - $55.3 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, 2015, the Company had $83.2 million (2014 - $79.9 million) in financial assets, considered to be past due, which have been outstanding for an average 80.5 days. The fair value of these financial assets is $71.5 million (2014 - $70.3 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, 2015**		December 31, 2014	
	millions of Canadian dollars	**% of total exposure**	millions of Canadian dollars	% of total exposure
Receivables, net				
Regulated utilities				
Residential	**$ 189.3**	20%	$ 195.1	26%
Commercial	**102.4**	10%	104.1	14%
Industrial	**29.2**	3%	26.3	4%
Other	**52.8**	5%	39.7	5%
	373.7	38%	365.2	49%
Trading group				
Credit rating of A- or above	**31.4**	3%	13.5	2%
Credit rating of BBB- to BBB+	**22.1**	2%	29.0	4%
Not rated	**30.8**	3%	44.8	6%
	84.3	8%	87.3	12%
Other accounts receivable	**120.1**	12%	61.7	8%
	578.1	58%	514.2	69%
Derivative Instruments (current and long-term)				
Credit rating of A- or above	**340.1**	34%	203.2	27%
Credit rating of BBB- to BBB+	**69.4**	7%	14.1	2%
Not rated	**7.6**	1%	11.2	2%
	417.1	42%	228.5	31%
	$ 995.2	100%	$ 742.7	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 2015**	December 31 2014
Cash collateral provided to others	**$ 106.9**	$ 45.8
Cash collateral received from others	**28.5**	2.9

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, 2015, the total fair value of these derivatives, in a liability position, was $445.3 million (December 31, 2014 – $204.8 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, 2015
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash flow hedges				
Power swaps	**$ 19.5**	**$ -**	**$ -**	**$ 19.5**
Foreign exchange forwards	**-**	**0.3**	**-**	**0.3**
	19.5	**0.3**	**-**	**19.8**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**1.4**	**-**	**1.4**
Foreign exchange forwards	**-**	**206.7**	**-**	**206.7**
Physical natural gas purchases and sales	**-**	**-**	**1.8**	**1.8**
	-	**208.1**	**1.8**	**209.9**
HFT derivatives				
Power swaps and physical contracts	**38.3**	**-**	**(7.8)**	**30.5**
Foreign exchange options	**-**	**0.4**	**-**	**0.4**
Natural gas swaps, futures, forwards, physical contracts and related transportation	**(0.3)**	**7.9**	**56.8**	**64.4**
	38.0	**8.3**	**49.0**	**95.3**
Other derivatives				
Foreign exchange forwards	**-**	**92.1**	**-**	**92.1**
	-	**92.1**	**-**	**92.1**
Total assets	**57.5**	**308.8**	**50.8**	**417.1**
Liabilities				
Cash flow hedges				
Power swaps	**4.6**	**-**	**-**	**4.6**
Foreign exchange forwards	**-**	**41.6**	**-**	**41.6**
	4.6	**41.6**	**-**	**46.2**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**16.1**	**-**	**16.1**
Heavy fuel oil purchases	**-**	**37.1**		**37.1**
Natural gas purchases and sales	**0.6**	**-**	**-**	**0.6**
Foreign exchange forwards		**10.5**	**-**	**10.5**
	0.6	**63.7**	**-**	**64.3**
HFT derivatives				
Power swaps and physical contracts	**15.2**	**-**	**(2.0)**	**13.2**
Foreign exchange options	**-**	**3.5**	**-**	**3.5**
Natural gas swaps, futures, forwards and physical contracts	**14.4**	**22.0**	**278.8**	**315.2**
	29.6	**25.5**	**276.8**	**331.9**
Other derivatives				
Interest rate swap	**-**	**2.9**	**-**	**2.9**
	-	**2.9**	**-**	**2.9**
Total liabilities	**34.8**	**133.7**	**276.8**	**445.3**
Net assets (liabilities)	**$ 22.7**	**$ 175.1**	**$ (226.0)**	**$ (28.2)**

As at				December 31, 2014
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Power swaps	$ 14.2	$ -	$ 8.7	$ 22.9
Foreign exchange forwards	-	0.1	-	0.1
	14.2	0.1	8.7	23.0
Regulatory deferral				
Commodity swaps and forwards				
Natural gas purchases and sales	0.1	-	-	0.1
Foreign exchange forwards	-	97.5	-	97.5
Physical natural gas purchases and sales	-	-	0.1	0.1
	0.1	97.5	0.1	97.7
HFT derivatives				
Power swaps and physical contracts	66.3	-	(3.4)	62.9
Natural gas swaps, futures, forwards and physical contracts	(1.8)	22.3	24.4	44.9
	64.5	22.3	21.0	107.8
Total assets	78.8	119.9	29.8	228.5
Liabilities				
Cash flow hedges				
Power swaps	$ 1.0	$ -	$ 3.2	$ 4.2
Foreign exchange forwards	-	15.0	-	15.0
	1.0	15.0	3.2	19.2
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	10.2	-	10.2
Natural gas purchases and sales	0.7	-	-	0.7
Heavy fuel oil purchases	-	25.5	-	25.5
Foreign exchange forwards	-	3.9	-	3.9
	0.7	39.6	-	40.3
HFT derivatives				
Power swaps and physical contracts	1.3	-	1.5	2.8
Natural gas swaps, futures, forwards and physical contracts	13.5	12.0	117.0	142.5
	14.8	12.0	118.5	145.3
Total liabilities	16.5	66.6	121.7	204.8
Net assets (liabilities)	$ 62.3	$ 53.3	$ (91.9)	$ 23.7

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2015 was as follows:

	Regulatory Deferral	*Cash Flow Hedges and HFT Derivatives*		
millions of Canadian dollars	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1, 2015	$ 0.1	$ 5.3	$ 24.4	$ 29.8
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	(7.1)	-	-	(7.1)
Increase (reduction) in benefit included in non-regulated fuel for generation and purchased power	-	-	-	-
Unrealized gains (losses) included in regulatory assets or liabilities	8.8	-	-	8.8
Total realized and unrealized gains (losses) included in non-regulated operating revenues	-	(8.8)	32.4	23.6
Net transfers out of Level 3	-	(4.3)	-	(4.3)
Balance, December 31, 2015	$ 1.8	$ (7.8)	$ 56.8	$ 50.8

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2015 was as follows:

	Regulatory Deferral	*Cash Flow Hedges and HFT Derivatives*		
millions of Canadian dollars	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1, 2015	$ -	$ 4.7	$ 117.0	$ 121.7
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	-	-	-	-
Increase (reduction) in benefit included in non-regulated fuel for generation and purchased power	-	-	-	-
Unrealized gains (losses) included in regulatory assets or liabilities	-	-	-	-
Total realized and unrealized gains (losses) included in non-regulated operating revenues	-	(2.3)	161.8	159.5
Net transfers out of Level 3	-	(4.4)	-	(4.4)
Balance, December 31, 2015	$ -	$ (2.0)	$ 278.8	$ 276.8

The Company evaluate the observable input of market data on a quarterly basis in order to determine if transfers between levels is appropriate. For the year ended December 31, 2015, transfer from Level 3 to Level 1 were a result of an increase in observable inputs.

Emera's Enterprise Risk Management group is responsible for valuation policies, processes and the measurement of fair value. Fair value accounting rules provide a three level hierarchy that prioritizes the inputs used to measure fair value. When possible, determining fair value is based primarily on observable market inputs in active markets.

Contracts with quoted prices available in active markets and exchanges for identical assets or liabilities are classified as level 1 in the hierarchy. For those contracts whereby pricing inputs are either directly or indirectly observable through markets, exchanges or third party sources, but do not qualify as level 1, are classified as level 2 in the hierarchy. For a level 3 classification, 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 its affiliates.

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; own credit risk; 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 also sources 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, 2015	
millions of Canadian dollars		**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets						
Regulatory deferral – Physical natural gas purchases and sales	$	**1.8**	Modelled pricing	Third-party pricing	$5.15 - $6.21	$5.72
				Probability of default	0.01%	0.01%
HFT derivatives – Power swaps and physical contracts		**(7.8)**	Modelled pricing	Third-party pricing	$26.27 - $129.20	$70.45
				Correlation factor	0.98% - 1.00%	0.99%
				Probability of default	0.00% - 0.02%	0.00%
				Discount rate	0.00% - 0.15%	0.01%
HFT derivatives – Natural gas swaps, futures, forwards, physical contracts and related transportation		**54.2**	Modelled pricing	Third-party pricing	$1.13 - $9.12	$3.26
				Probability of default	0.00% - 0.10%	0.01%
				Discount rate	0.00% - 0.33%	0.04%
		2.6	Modelled pricing	Third-party pricing	$1.25 - $15.74	$6.19
				Basis adjustment	(0.06)% - 0.95%	0.68%
				Probability of default	0.00% - 0.09%	0.00%
				Discount rate	0.00% - 0.08%	0.00%
Total assets		**50.8**				
Liabilities						
HFT derivatives – Power swaps and physical contracts	$	**(2.0)**	Modelled pricing	Third-party pricing	$26.27 - $129.20	$70.82
				Correlation factor	0.98% - 1.00%	0.99%
				Own credit risk	0.00% - 0.02%	0.00%
				Discount rate	0.00% - 0.15%	0.01%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts		**278.8**	Modelled pricing	Third-party pricing	$0.74- $10.59	$5.58
				Probability of default	0.00% - 0.03%	0.00%
				Discount rate	0.00% - 0.12%	0.01%
Total liabilities		**276.8**				
Net assets (liabilities)	$	**(226.0)**				

As at					December 31, 2014
millions of Canadian dollars	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets					
Cash flow hedges – Power and gas swaps	$ **8.7**	Modelled pricing	Third-party pricing	$23.23-$114.99	$53.97
			Probability of default	0.05% - 0.06%	0.05%
			Discount rate	5.06% - 7.53%	6.06%
Regulatory deferral – Physical natural gas purchases and sales	**0.1**	Modelled pricing	Third-party pricing	$9.52 - $12.94	$9.52
			Probability of default	0.05%	0.05%
HFT derivatives – Power swaps and physical contracts	**(4.4)**	Modelled pricing	Third-party pricing	$46.65 - $103.27	$70.69
			Probability of default	0.06% - 0.06%	0.06%
			Discount rate	0.00% - 4.15%	0.47%
	1.0	Modelled pricing	Third-party pricing	$27.61 - $127.96	$62.04
			Correlation factor	0.99% - 1.0%	0.99%
			Probability of default	0.04% - 0.39%	0.14%
			Discount rate	0.00% - 48.63%	11.87%
HFT derivatives – Natural gas swaps, futures, forwards and	**24.4**	Modelled pricing	Third-party pricing	$1.19 - $11.36	$5.56
			Probability of default	0.01% - 2.26%	0.46%
			Discount rate	0.00% - 67.72%	5.28%
Total assets	**29.8**				
Liabilities					
Cash flow hedges – Power and gas swaps	$ **3.2**	Modelled pricing	Third-party pricing	$23.23- $114.99	$53.97
			Own credit risk	0.06% - 0.06%	0.06%
			Discount rate	5.06% - 7.53%	6.06%
HFT derivatives – Power swaps and physical contracts	**1.2**	Modelled pricing	Third-party pricing	$32.99 - $127.96	$74.58
			Correlation factor	0.99% - 1.00%	$0.99
			Own credit risk	0.06% - 0.06%	0.06%
			Discount rate	0.00% - 48.63%	15.37%
	0.3	Modelled pricing	Third-party pricing	$46.45 - $103.27	$70.69
			Own credit risk	0.06% - 0.06%	0.06%
			Discount rate	0.00% - 4.15%	0.47%
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	**117.0**	Modelled pricing	Third-party pricing	$1.60 - $14.13	$3.81
			Basis adjustment	(0.01)% - 0.66%	0.21%
			Own credit risk	0.06% - 0.06%	0.06%
			Discount rate	0.00% - 31.53%	3.52%
Total liabilities	**121.7**				
Net assets (liabilities)	$ **(91.9)**				

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, 2015**		December 31, 2014	
millions of Canadian dollars	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-term debt (including current portion)	$ **4,024.8**	$ **4,486.7**	$ 3,754.8	$ 4,382.9

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 ASSETS AND LIABILITIES

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 2015 and 2014 was 8.75 per cent to 9.25 per cent based on an actual average regulated common equity component of up to 40 per cent. NSPI has a FAM, which enables it 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.

On December 21, 2012, the UARB approved a General Rate Application ("GRA") settlement agreement between NSPI and customer representatives which resulted in an average net rate increase of 3 per cent by customer class effective January 1, 2013 and January 1, 2014. To achieve the net 3 per cent increase in rates, the UARB approved a rate stabilization plan under which a portion of non-fuel costs from 2013 and 2014 could be deferred for future recovery. NSPI committed to $27.5 million in non-fuel cost savings over a two-year period beginning in fiscal 2013.

As at December 2014, NSPI had under recovered approximately $86.1 million in Fuel Costs. Pursuant to NSPI's FAM Plan of Administration, this amount would be recovered commencing in 2015. On November 25, 2014, the UARB approved a settlement agreement that resulted in approximately $56.0 million of the 2014 outstanding FAM balance being collected in 2015. In addition, the UARB directed NSPI to transfer $38.2 million of the payable balance of the rate stabilization deferral account to reduce the FAM balance of $86.1 million, resulting in a revised balance of $47.9 million at December 31, 2014.

Through a related settlement agreement with stakeholders approved in December 2014, NSPI agreed to apply non-fuel revenues above that required to achieve its approved range of return to reduce the FAM deferral account. This was effective as of January 1, 2015, until the next GRA approval or similar process where non-fuel rates are adjusted. This settlement agreement required NSPI to contribute a minimum of $41.3 million to the FAM deferral account by the end of 2015.

As at December 31, 2015, NSPI had exceeded the minimum required contribution of $41.3 million through the $38.2 million contributed in 2014 referred to above and an additional $44.7 million applied in 2015. Of the $44.7 million applied in 2015, $18.3 million relates to changes to South Canoe and Sable Wind Projects tax treatment.

On December 21, 2015, the UARB approved NSPI's setting of the 2016 base cost of fuel and its recovery of prior period unrecovered fuel related costs as submitted in NSPI's August and November 2015 filings. The recovery of these costs will begin January 1, 2016. The approved customer rates seek to recover $13.7 million of prior years' unrecovered Fuel Costs in 2016 and the current FAM asset on the balance sheet. This results in a combined average rate decrease for customers of approximately 1 per cent.

The excess non-fuel revenues in 2015 include a benefit of $18.3 million which is the result of the changes to South Canoe and Sable Wind Projects tax treatments, as legislated by the Electricity Plan Act. The Electricity Plan Act also directs NSPI to apply sufficient 2015 excess non-fuel revenues, so as to offset 2016 fuel rate increases in certain classes. This amount totals $4.6 million and is included in the $13.7 million current FAM asset on the Consolidated Balance Sheets. The remaining 2015 excess non-fuel revenues of $40.1 million, plus interest, have been deferred for future periods beyond 2016, as further directed by the Electricity Plan Act and are classified as long-term FAM liability on the Consolidated Balance Sheets.

Emera Maine

Emera Maine's core businesses are the transmission and distribution of electricity, with distribution operations and stranded cost recoveries regulated by the Maine Public Utilities Commission ("MPUC"). The 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>

Emera Maine's distribution businesses operate under a traditional cost-of-service regulatory structure, and distribution rates are set by the MPUC. Prior to July 1, 2014, the allowed ROE was 10.2 per cent, on a common equity component of 50 per cent.

On July 1, 2014, Emera Maine's distribution rates increased by nine per cent, including the recovery, over five years, of approximately $5 million USD of costs associated with a major ice storm in Maine in late December 2013. Also, effective July 1, 2014, the allowed ROE became 9.55 per cent, on a common equity component of 49 per cent.

<u>Transmission Operations</u>

There are two transmission districts in Emera Maine, corresponding to the service territories of the two pre-merger entities.

Bangor Hydro District

Transmission rates for Bangor Hydro District's (the franchise electric service territory associated with the former Bangor Hydro Electric Company in portions of the Maine counties of Penobscot, Hancock, Washington, Waldo, Piscataquis, and Aroostook) are regulated by the FERC and set annually on June 1, based on a formula utilizing prior year actual transmission investments, adjusted for current year forecasted transmission investments. The allowed ROE up to October 15, 2014, for these local transmission investments was 11.14 per cent. Effective October 16, 2014, the allowed ROE changed to 10.57 per cent, pending two outstanding complaints filed with the FERC to challenge the ISO-New England Open Access Transmission Tariff-allowed base ROE of 11.14 per cent. The common equity component is based upon the prior calendar year actual average balances. Effective June 1, 2015, transmission rates for the Bangor Hydro district increased by approximately 21 per cent in connection with its annual transmission formula rate filing (2014 – increased by 13 per cent). The increase is associated primarily with the under-recovery of prior year regional transmission revenues collected in local rates, as well as the recovery of increased transmission plant in service.

Bangor Hydro District's bulk transmission assets are managed by ISO-New England ("ISO-NE") as part of a region-wide pool of assets. ISO-NE manages the region's bulk power generation and transmission systems and administers the open access transmission tariff. Currently, the Bangor Hydro District, 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 FERC approved formula that is updated June 1 each year. This formula is based on prior year regionally funded transmission investments, adjusted for current year forecasted investments. Until October 15, 2014, Bangor Hydro District's allowed ROE for these transmission investments ranged from 11.64 per cent to 12.64 per cent. Effective October 16, 2014, the transmission investments allowed ROE changed to a range from 11.07 per cent to 11.74 per cent, pending the two aforementioned complaints filed with FERC. The common equity component is based upon the prior calendar year average balances. The participating transmission providers are also required to contribute to the cost of service of such transmission assets on a ratable basis according to the proportion of the total New England load that their customers represent.

On June 1, 2015, Bangor District's regionally recoverable transmission investments and expenses decreased by 6 per cent (2014 – increased by 7 per cent).

MPS District

Local transmission rates for MPS District's (the franchise electric service territory associated with the former Maine Public Service Company in northern Maine) are regulated by the FERC and are set annually on June 1 for wholesale and July 1 for retail customers based on a formula utilizing prior year actual transmission investments and expenses, adjusted for current year forecasted investments. The current allowed ROE for transmission operations is 10.2 per cent. The common equity component is based upon the prior calendar year actual average balances. Effective June 1, 2015 the transmission rates for the Maine Public Service district decreased by approximately 24 per cent for wholesale customers (2014 -increased by 2 per cent) and on July 1, 2015 decreased by 22 per cent for retail customers (2014 - increased by 11 per cent) in connection with its annual transmission formula rate filing. These decreases were primarily due to an increase in wholesale transmission revenue that allows for a decrease in local customer transmission rates.

The MPS District electric service territory is not connected to the New England bulk power system and it is not a member of ISO-NE. MPS District is not a party to the previously discussed ROE complaints at the FERC.

Stranded Cost Recoveries

Stranded cost recoveries in Maine are set by the MPUC. Electric utilities are permitted 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, determined under a traditional cost-of-service approach and are fully recoverable. Each year on July 1, stranded cost rates in the Bangor District are adjusted to reflect recovery of cost deferrals for the prior stranded costs rate year under the full recovery mechanism, as well as factor in any new stranded cost information.

Bangor District

Bangor District's net regulatory assets primarily include the costs associated with the restructuring of an above-market power purchase contract and deferrals associated with reconciling stranded costs. These net regulatory assets total approximately $19.7 million as at December 31, 2015 (2014 – $25.1 million) or 1.8 per cent of Emera Maine's net asset base (2014 – 2.3 per cent).

On July 1, 2014, the Bangor District stranded cost rates decreased by 10 per cent. Earlier, on March 1, 2014, stranded costs rates had increased by 20 per cent. The allowed ROE used in setting the new rates on July 1, 2014, and March 1, 2014, was 5.9 per cent, with a common equity component of 48 per cent. This July 1, 2014 rate decrease remained in effect for all of 2015 and there was no rate change on July 1, 2015.

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 stabilize 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 District

Effective January 1, 2015, the stranded cost rates for the Maine Public Service district decreased by approximately 150 per cent. This was principally due to the flow-back to customers of certain benefits received by Emera Maine from Maine Yankee associated with litigation with the United States Department of Energy on nuclear waste disposal. The allowed ROE used in setting the new rates on January 1, 2015 was 6.75 per cent, with a common equity component of 48 per cent. The reduced stranded cost revenues are offset by reductions in expense and do not affect earnings. This January 1, 2015, rate decrease remained in effect for all of 2015 and there was no rate change on July 1, 2015.

The Barbados Light & Power Company Limited

BLPC is a vertically integrated utility and 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 generate, transmit and distribute electricity on the island until 2028.

BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. BLPC's approved regulated return on rate base for 2015 and 2014 was 10 per cent.

All BLPC fuel costs are passed to customers through the fuel pass-through mechanism which provides the opportunity to recover all fuel costs in a timely manner. The Fair Trading Commission, Barbados has approved the calculation of the fuel charge, which is adjusted on a monthly basis.

Dominica Electricity Services Ltd

Domlec is an integrated utility on the island of Dominica and is regulated by the Independent Regulatory Commission, Dominica

On October 7, 2013, the Independent Regulatory Commission, Dominica issued a Transmission, Distribution & Supply License and a Generation License, both of which came into effect on January 1, 2014, for a period of 25 years. Domlec's approved allowable regulated return on rate base for 2015 and 2014 was 15 per cent.

Domlec fuel costs are passed to customers through a fuel pass-through mechanism which provides the opportunity to recover substantially all fuel costs in a timely manner.

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. GBPC's approved regulated return on rate base for 2015 and 2014 was 10 per cent.

For the years ended December 31, 2015 and 2014, all GBPC fuel costs are passed to customers through a fuel pass-through mechanism which provides the opportunity to recover substantially all fuel costs in a timely manner.

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 2015**	December 31 2014
Regulatory assets		
Deferred income tax regulatory assets	**$ 431.3**	$ 340.1
Deferrals related to derivative instruments	**67.7**	45.6
Unamortized defeasance costs	**45.7**	52.5
Demand side management deferral (note 5)	**36.4**	-
Stranded cost recovery	**28.5**	24.9
Fuel adjustment mechanism (note 5)	**13.7**	47.9
Pension and post-retirement medical plan	**11.9**	10.4
Hydro-Quebec Obligation	**7.6**	6.8
Stranded cost revenue & purchase power reconciliation deferrals	**6.1**	8.0
2014 Maine storm	**6.1**	5.3
Purchase power contracts	**5.9**	7.0
Large industrial customers fixed cost deferral (note 5)	**-**	15.8
Other	**38.6**	38.4
	$ 699.5	$ 602.7
Current	**$ 94.2**	$ 115.0
Long-term	**605.3**	487.7
Total regulatory assets	**$ 699.5**	$ 602.7
Regulatory liabilities		
Deferrals related to derivative instruments	**$ 209.9**	$ 97.7
Self-Insurance Fund	**86.8**	72.8
Fuel adjustment mechanism (note 5)	**42.0**	-
Deferred income tax regulatory liabilities	**17.6**	17.7
Other	**14.3**	13.7
	$ 370.6	$ 201.9
Current	**$ 98.9**	$ 43.0
Long-term	**271.7**	158.9
Total regulatory liabilities	**$ 370.6**	$ **201.9**

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, unless specifically directed otherwise by a regulator.

Deferrals Related to Derivative Instruments

NSPI and GBPC defers changes in fair value of derivatives that are documented as economic hedges or that do not qualify for normal purchase normal sale ("NPNS") exemption, as a regulatory asset or liability. The realized gain or loss is recognized when the hedged item settles in fuel for generation and purchased power or inventory, depending on the nature of the item being economically hedged.

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, 2015, totaled $0.8 billion (2014 – $0.7 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 approved by the UARB.

2015 DSM Deferral

As discussed in Note 5, following the new energy efficiency legislation, the UARB approved the implementation of the 2015 DSM deferral set at $35 million for 2015 and recoverable from customers over an eight year period beginning in 2016. The change in the 2015 DSM regulatory asset balance for the year ended December 31 consisted of the following:

millions of Canadian dollars		**2015**
DSM regulatory asset – Balance as at January 1	**$**	**-**
Current period Program Costs		35.0
Interest on DSM balance		1.4
DSM regulatory asset – Balance as at December 31	**$**	**36.4**

Stranded Cost Recovery

Due to the decommissioning of a steam turbine in GBPC during 2012, the GBPA approved the recovery of a $21.4 million USD stranded cost through future electricity rates. These amounts are scheduled to be recovered beginning January 1, 2016.

Fuel Adjustment Mechanism

As discussed in Note 5, the UARB approved the implementation of a FAM for NSPI effective January 1, 2009. The change in the FAM balance for the years ended December 31 consisted of the following:

millions of Canadian dollars		**2015**		2014
FAM regulatory asset – Balance as at January 1	**$**	**47.9**	**$**	**86.4**
Under (over) recovery of current year Fuel Costs		24.1		(1.3)
Rebate to (recovery from) customers of prior years' Fuel Costs		(56.0)		-
FAM audit disallowance, including interest adjustment		-		(6.0)
Application of non-fuel revenues		(44.7)		(38.2)
Interest on FAM balance		0.4		7.0
FAM regulatory asset (liability) – Balance as at December 31	**$**	**(28.3)**	**$**	**47.9**

Details of the changes are discussed further in note 5. The FAM balance is recorded on the balance sheet as a current FAM asset of $13.7 million, to be recovered in 2016 and a long-term FAM liability of $42.0 million to be applied during 2017 through 2019 as legislated.

Pension and Post-Retirement 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 post-retirement medical benefit plans were eliminated as a result of the Bangor Hydro Electric Company and Maine Public Service Company mergers. As a result, a regulatory asset of $30 million, equal to these unrecognized amounts, was established at the merger dates. Emera Maine is 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 post-retirement benefit expense.

Hydro-Quebec Obligation

The obligation associated with Hydro-Quebec represents the estimated present value of Emera Maine'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.

Stranded Cost Revenue & Purchased Power Reconciliation Deferral

Emera Maine has 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 recover these cost deferrals.

2014 Maine Storm

In early November 2014, Emera Maine experienced a major storm in its service territory, with over one-third of the Company's customers experiencing power outages at the peak of storm. Due to the volume of power outages and significant damage to the electrical system, numerous external resources were utilized to assist with the restoration of electrical service. The total incremental costs associated with the service restoration during the storm event amounted to approximately $5.3 million ($4.6 million USD), and the Company has recorded this amount as a regulatory asset on its consolidated balance sheets as of December 31, 2014. During Q2 2015, the Company made a request to the MPUC for a $5.4 million USD recovery of costs associated with this storm, as well as two other major storms that were expensed in 2014. In June 2015, Emera Maine reached agreement with the MPUC to recover $4.1 million USD of the $5.4 million USD being sought. Emera Maine is recording carrying costs on this deferral retroactive to January 1, 2015 and going forward until the $4.1 million USD is included in rates. The difference between $5.4 million USD originally requested for approval and the $4.1 million USD approved by the MPUC was expensed in Q2 2015.

Purchase Power Contracts

Emera Maine has power purchase contracts, which it was required to negotiate when oil prices were high, with several independent power producers. Bangor Hydro Electric Company 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 Emera Maine to defer these costs and recover them in stranded cost rates. The contract restructuring costs are being recovered over a 20-year period ending in June 2018. In 2011, Bangor Hydro Electric Company entered into a 20-year power purchase contract with a 60-MW wind farm to purchase 20 per cent of the energy generated. Also in 2011, Bangor Hydro Electric Company entered into a 20-year power purchase contract with a 1-MW biomass generator to purchase

100 per cent of the energy generated. As with the Company's other power purchase contracts, the MPUC has allowed Bangor Hydro Electric Company full cost recovery for these contracts.

Large Industrial Customers Fixed Cost Deferral

The UARB approved a FCR for 2012 to address uncertainty associated with the operations of two large industrial customers who experienced financial challenges and idled their mills. Where actual sales to these customers in 2012 was less than expected when rates were set, the resultant shortfall in contribution toward non-fuel costs was deferred as a regulatory asset for future recovery. The 2013 GRA settlement agreement, approved on December 21, 2012 by the UARB, allowed recovery of this deferral from customers over a three-year period commencing January 1, 2013.

The change in the large industrial customers regulatory asset balance for the years ended December 31 consisted of the following table:

millions of Canadian dollars		**2015**		2014
Large industrial customers regulatory asset – Balance as at January 1	**$**	**15.8**	**$**	**33.0**
Recovery of regulatory asset recorded as regulatory amortization		(16.4)		(19.1)
Interest on large industrial customers FCR balance		0.6		1.9
Large industrial customers regulatory asset – Balance as at December 31	**$**	**-**	**$**	**15.8**

Self-Insurance Fund

ECI 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. ECI holds a variable interest in the SIF, for which it was determined that ECI was the primary beneficiary and, accordingly, the SIF must be consolidated by ECI. In its determination that ECI controls the SIF, management considered that in substance the activities of the SIF are being conducted on behalf of ECI's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because ECI, 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. Any withdrawal of SIF Fund assets by the Company would be subject to existing regulations.

18. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera provides energy, construction and other services and enters into transactions with its subsidiaries, associates and other related companies on terms similar to those offered to non-related parties. Inter-company balances and inter-company transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate-regulated entities, is recorded in non-regulated operating revenues, with an offset to property, plant and equipment, regulated fuel for generation and purchased power, or operating, maintenance and general, depending on the nature of the transaction. 2014 balances have been retrospectively restated, consistent with this approach. Below are transactions between Emera and its associated companies reported in the Consolidated Statements of Income:

For the millions of Canadian dollars			Year ended December 31	
			2015	2014
	Nature of Service	**Presentation**		
Sales to:				
APUC subsidiary	Net sale of natural gas and transportation	Operating revenue – non-regulated	**$ 3.0**	$ 4.4
NWP	Energy management services	Operating revenue – regulated	**0.3**	1.1
Purchases from:				
M&NP	Natural gas transportation capacity	Regulated fuel for generation and purchased power	**4.5**	3.6
M&NP	Natural gas transportation capacity	Operating revenue – non-regulated	**(23.4)**	(23.8)
NWP	Purchase of power	Regulated fuel for generation and purchased power	**$ 0.3**	$ 1.9

Operating revenue – non-regulated includes intercompany profit relating to the sale of natural gas, sale of power, construction, operations management and engineering services, and hedging services to rate-regulated subsidiaries of Emera totaling $1.6 million for the year ended December 31, 2015 (2014 – $4.2 million).

Amounts reported on Emera's Consolidated Balance Sheets due (to) from its equity investments are summarized in the following table:

As at millions of Canadian dollars	December 31 2015	December 31 2014
Due from related parties:		
Subsidiary of APUC – current (1)	**$ 0.7**	$ -
NSPML – current	**1.6**	3.5
M&NP – loan receivable – long-term	**2.5**	2.5
Due to related parties:		
M&NP – current	**(2.1)**	(1.6)
Net due from (to) related parties	**$ 2.7**	**$ 4.4**

(1) Amount due from a subsidiary of APUC is included in accounts receivable.

All amounts are under normal interest and credit terms, except for a loan receivable from M&NP bearing interest at 1 per cent per annum maturing on November 30, 2019.

19. OTHER CURRENT ASSETS

Other current assets consisted of the following:

As at millions of Canadian dollars	**December 31 2015**	December 31 2014
Net investment in direct financing lease	**$ 5.4**	$ 5.1
Dividend receivable	**6.7**	5.0
Capitalized transportation capacity (1)	**222.7**	70.5
	$ 234.8	$ 80.6

(1) Capitalized transportation capacity represents the value of transportation received by EES on asset management agreements at the inception of the contracts. The asset is amortized over the term of each contract.

20. PROPERTY, PLANT AND EQUIPMENT

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

As at millions of Canadian dollars	Estimated useful life	**December 31 2015**	December 31 2014
Generation	3 to 131	**$ 4,957.0**	$ 4,415.5
Transmission	10 to 65	**1,508.2**	1,331.1
Distribution	11 to 80	**2,461.7**	2,182.9
General plant and other	5 to 57	**786.9**	722.5
Total cost		**9,713.8**	8,652.0
Less: Accumulated depreciation		**(3,732.4)**	(3,362.0)
		5,981.4	5,290.0
Construction work in progress		**206.6**	320.2
Net book value		**$ 6,188.0**	$ 5,610.2

For the year ended December 31, 2015, AFUDC of $6.6 million (2014 – $12.0 million) was capitalized to “Property, plant and equipment”.

As a result of regulator-approved accounting policies and depreciation rates, NSPI, Emera Maine and GBPC 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 USGAAP accounting standards including depreciation rates, AFUDC and overhead costs, cannot be separately determined. Cumulative deferred accretion expense related to AROs was $7.9 million as at December 31, 2015 (2014 – $10.3 million).

21. 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, New Brunswick, Newfoundland and Labrador, Maine, Connecticut, Rhode Island, Barbados, Dominica and Grand Bahama Island.

Effective April 1, 2015, Emera Maine amended certain post-retirement medical benefits which resulted in a reduction in the pension and post-retirement benefits liability.

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		2015	Years ended December 31	2014
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	**$ 1,469.7**	**$ 101.9**	$ 1,253.3	$ 86.0
Service cost	**22.1**	**2.8**	17.1	2.8
Plan participant contributions	**7.9**	**0.3**	7.5	0.1
Interest cost	**58.7**	**3.5**	61.7	4.2
Plan amendments	**-**	**(26.7)**	-	-
Benefits paid	**(61.0)**	**(5.8)**	(60.0)	(4.9)
Actuarial losses	**(15.4)**	**1.1**	175.1	8.7
Special termination	**-**	**-**	(0.1)	-
Foreign currency translation adjustment	**37.7**	**10.4**	15.1	5.0
Balance, December 31	**1,519.7**	**87.5**	1,469.7	101.9
Change in Plan assets				
Balance, January 1	**1,204.7**	**4.6**	1,070.0	4.0
Employer contributions	**23.0**	**5.6**	52.9	4.8
Plan participant contributions	**8.3**	**-**	7.5	-
Benefits paid	**(61.0)**	**(5.6)**	(60.0)	(4.8)
Actual return on assets, net of expenses	**96.3**	**(0.1)**	122.8	0.2
Foreign currency translation adjustment	**29.1**	**0.9**	11.5	0.4
Balance, December 31	**1,300.4**	**5.4**	1,204.7	4.6
Funded Status, end of year	**$ (219.3)**	**$ (82.1)**	$ (265.0)	$ (97.3)

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

		2015		2014
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 1,489.4**	**$ 87.5**	$ 1,437.9	$ 101.9
Fair value of Plan Assets	**1,261.3**	**5.4**	1,167.0	4.6
Funded Status	**$ (228.1)**	**$ (82.1)**	$ (270.9)	$ (97.3)

The Accumulated Benefit Obligation ("ABO") for the defined benefit pension plans was $1,426.5 million as at December 31, 2015 (2014 – $1,404.8 million). As at December 31, the aggregate financial position for those plans with an ABO in excess of the Plan assets was as follows:

Plans with ABO in excess of Plan assets

	2015	2014
millions of Canadian dollars	**Defined benefit pension plans**	Defined benefit pension plans
ABO	**$ 1,424.1**	$ 1,373.8
Fair value of Plan Assets	**1,261.3**	1,167.0
Funded Status	**$ (162.8)**	$ (206.8)

Balance Sheet

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

	2015		2014	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Current liabilities	**$ (3.9)**	**$ (3.1)**	$ (3.6)	$ (3.9)
Long-term liabilities	**(224.4)**	**(79.0)**	(267.3)	(93.4)
Other asset (noncurrent)	**8.7**	**-**	5.9	-
Amount included in deferred tax asset	**20.6**	**(3.2)**	22.8	4.1
AOCI after tax adjustment	**328.6**	**(9.2)**	420.4	6.3
Net amount recognized at end of year	**$ 129.6**	**$ (94.5)**	$ 178.2	$ (86.9)

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCI. The following tables provide detail on the change in AOCI during fiscal 2015 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	$ 447.7	$ (4.5)
Amortized in current period	(47.5)	0.8
Current year addition to AOCI	(47.0)	-
Transfer to other regulatory asset (1)	(0.1)	-
Foreign currency translation adjustment	(0.2)	-
Balance, December 31	$ 352.9	$ (3.7)
Non-pension benefits plans		
Balance, January 1	$ 16.8	$ (6.5)
Amortized in current period	(1.6)	6.3
Current year addition to AOCI	1.3	(27.1)
Transfer to other regulatory asset (1)	(0.1)	(1.5)
Foreign currency translation adjustment	(1.4)	1.4
Balance, December 31	$ 15.0	$ (27.4)

(1) For Emera Maine, 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.

	2015		2014	
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	**$ 352.9**	**$ 15.0**	$ 447.7	$ 16.9
Past service (gains)	**(3.7)**	**(27.4)**	(4.5)	(6.5)
Total AOCI on a pre-tax basis	**349.2**	**(12.4)**	443.2	10.4
Less: Amount included in deferred tax asset	**(20.6)**	**3.2**	(22.8)	(4.1)
Net amount in AOCI after tax adjustment	**$ 328.6**	**$ (9.2)**	$ 420.4	$ 6.3

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

Benefit Cost Components	**2015**		2014	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 22.1**	**$ 2.8**	$ 17.1	$ 2.8
Interest cost	**58.7**	**3.5**	61.7	4.2
Expected return on plan assets	**(64.6)**	**(0.3)**	(63.2)	(0.2)
Current year amortization of:				
Actuarial losses	**47.5**	**1.6**	35.9	0.1
Past service costs (gains)	**(0.8)**	**(6.3)**	(0.8)	(1.7)
Special termination	**-**	**-**	(0.1)	-
Total	**$ 62.9**	**$ 1.3**	$ 50.6	$ 5.2

The expected return on plan assets is determined based on the market-related value of plan assets of $1,088.7 million as at January 1, 2015 (2014 – $995.1 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 and non-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	35%	to	50%
Equities:			
Canadian	12%	to	22%
Non-Canadian (World)	36%	to	50%

Non-Canadian Pension Plans

Asset Class	Target Range at Market (weighted average)		
Short-term securities	0%	to	10%
Fixed income	30%	to	50%
Equities:			
US	24%	to	47%
Non-US	14%	to	26%

For Emera Maine, 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, 2015, by asset category, are as follows:

				December 31, 2015
millions of Canadian dollars	**NAV**	**Level 1**	**Total**	**Percentage**
Cash and cash equivalents		**$ 11.6**	**$ 11.6**	**0.9 %**
Equity securities:				
Canadian equity		**189.8**	**189.8**	**14.6 %**
US equity		**239.9**	**239.9**	**18.4 %**
Other equity		**240.0**	**240.0**	**18.5 %**
Other investments measured at NAV	**$ 619.1**	**-**	**619.1**	**47.6 %**
Total	**$ 619.1**	**$ 681.3**	**$ 1,300.4**	**100.0 %**

				December 31, 2014
millions of Canadian dollars	NAV	Level 1	Total	Percentage
Cash and cash equivalents		$ 6.3	$ 6.3	0.5 %
Equity securities:				
Canadian equity		125.3	125.3	10.4 %
US equity		234.5	234.5	19.5 %
Other equity		234.5	234.5	19.5 %
Other investments measured at NAV	$ 604.1	-	604.1	50.1 %
Total	$ 604.1	$ 600.6	$ 1,204.7	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, 2015 and 2014.

Investments in Emera or NSPI

As at December 31, 2015 and 2014, 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 as required.

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.

Emera Maine provides retiree medical benefits to certain groups 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 per cent 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.

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	30%	to	60%
Non-US	0%	to	60%

The fair values of investments as at December 31, 2015, by asset category, are as follows:

millions of Canadian dollars	NAV	Level 1	December 31,2015 Total	Percentage
Cash and cash equivalents		**$ 1.4**	**$ 1.4**	**25.9 %**
Other investments measured at NAV	**$ 4.0**		**4.0**	**74.1 %**
Total	**$ 4.0**	**$ 1.4**	**$ 5.4**	**100.0 %**

millions of Canadian dollars	NAV	Level 1	December 31, 2014 Total	Percentage
Cash and cash equivalents		$ 1.2	$ 1.2	26.1 %
Other investments measured at NAV	$ 3.4	-	3.4	73.9 %
Total	$ 3.4	$ 1.2	$ 4.6	100.0 %

Refer to Note 1(X), "*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, 2015 and 2014.

Investments in Emera or NSPI

As at December 31, 2015 and 2014, 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		
2016	$ 19.7	$ 5.6
Expected benefit payments		
2016	65.5	5.6
2017	70.6	5.6
2018	75.1	6.1
2019	79.9	6.3
2020	85.2	6.7
2021 – 2025	488.1	35.9

Assumptions

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

	2015		2014	
(weighted average assumptions)	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Benefit obligation – December 31:				
Discount rate	**4.02 %**	**4.04 %**	3.99 %	3.98 %
Rate of compensation increase	**3.07 %**	**3.50 %**	3.07 %	3.50 %
Health care trend - initial (next year)	**-**	**5.50 %**	-	5.20 %
- ultimate	**-**	**4.20 %**	-	4.30 %
- year ultimate reached	**-**	**2020**	-	2020
Benefit cost for year ended December 31:				
Discount rate	**3.99 %**	**3.98 %**	4.99 %	4.90 %
Expected long-term return on plan assets	**5.91 %**	**-**	6.36 %	-
Rate of compensation increase	**3.07 %**	**3.50 %**	3.29 %	3.50 %
Health care trend - initial (current year)	**-**	**5.90 %**	-	5.20 %
- ultimate	**-**	**4.30 %**	-	4.40 %
- year ultimate reached	**-**	**2020**	-	2020

Figures shown are weighted averages. Actual assumptions used may differ by plan.

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.

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 2015:

millions of Canadian dollars	Increase	Decrease
Service cost and interest cost	**$** 1.1	$ (1.0)
Accumulated post-retirement benefit obligation, December 31	9.2	(7.5)

Sensitivity Analysis for Defined Benefit Pension Plans

The impact on the 2015 benefit cost of a 25 basis point change (0.25 per cent) in the discount rate and asset return assumptions is as follows:

millions of Canadian dollars	Increase	Decrease
Discount rate assumption	**$** (5.4)	$ 5.4
Asset rate assumption	(2.7)	2.6

Amounts to be Amortized in the Next Fiscal Year

The following table shows the amounts from the AOCI, which are expected to be recognized as part of the net periodic benefit cost in fiscal 2016:

millions of Canadian dollars	2016 Defined benefit pension plans	2016 Non-pension benefit plans
Actuarial gains (losses)	$ (41.4)	$ (2.2)
Past service gains	0.7	8.7
Total	$ (40.7)	$ 6.5

Defined Contribution Plan

Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2015 was $9.0 million (2014 – $9.6 million).

22. 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 2015**	December 31 2014
Total minimum lease payments to be received	**$ 1,201.6**	$ 1,263.2
Less: amounts representing estimated executory costs	**(212.5)**	(222.1)
Minimum lease payments receivable	**$ 989.1**	$ 1,041.1
Estimated residual value of leased property (unguaranteed)	**183.0**	183.0
Less: unearned finance lease income	**(686.6)**	(734.5)
Net investment in direct financing lease	**$ 485.5**	$ 489.6
Principal due within one year (included in "Other current assets")	**5.4**	5.1
Net investment in direct financing lease – long-term	**$ 480.1**	$ 484.5

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

For the millions of Canadian dollars	Year ended December 31 2016	2017	2018	2019	2020
Minimum lease payments to be received	$ 61.6	$ 61.6	$ 61.6	$ 61.6	$ 61.6
Less: amounts representing estimated executory costs	(9.8)	(9.9)	(10.1)	(10.3)	(10.5)
Minimum lease payments receivable	$ 51.8	$ 51.7	$ 51.5	$ 51.3	$ 51.1

23. AVAILABLE-FOR-SALE INVESTMENTS

The available-for-sale investments consist primarily of debt and equity investments held in trust on behalf of BLPC's Self Insurance Fund ("SIF") 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. Any withdrawal of SIF Fund assets by the Company would be subject to existing regulations.

In addition, there are debt and equity investments related to Emera Reinsurance Limited, for captive insurance purposes.

Emera has classified these investments as available-for-sale and recorded all such investments at their fair market value as at December 31, 2015.

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

As at millions of Canadian dollars	NAV	Level 1	Level 2	Level 3	December 31 2015
Common shares		$ 16.4	$ -	$ -	$ 16.4
Corporate bonds, debentures, short and medium term notes		-	34.6	-	34.6
Government bonds		-	11.7	-	11.7
Other investments measured at NAV	53.3				53.3
	$ 53.3	$ 16.4	$ 46.3	$ -	$ 116.0

As at millions of Canadian dollars	NAV	Level 1	Level 2	Level 3	December 31 2014
Common shares	$	$ 13.8	$ -	$ -	$ 13.8
Corporate bonds, debentures, short and medium term notes		-	36.1	-	36.1
Government bonds		-	2.8	-	2.8
Other investments measured at NAV	31.7				31.7
	$ 31.7	$ 13.8	$ 38.9	$ -	$ 84.4

The fair value of financial instruments traded in active markets, and classified as level one, 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. Fair values within the level two category are determined through the use of quoted prices in active markets for similar assets, which in some cases, are adjusted for factors specific to the asset.

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

As at millions of Canadian dollars	December 31 2015	December 31 2014
Balance, beginning of the year	$ 84.4	$ 74.2
Additions	34.5	30.3
Disposals	(16.5)	(27.1)
	$ 102.4	$ 77.4
Change in fair value		
Realized (loss) gain recognized in income	-	(0.8)
Gain (loss) recognized in other comprehensive income during the period	13.6	7.8
	$ 13.6	$ 7.0
Balance, end of the period	$ 116.0	$ 84.4

There were no impairment provisions for available-for-sale investments for the twelve months ended December 31, 2015 (2014 - nil).

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

As at millions of Canadian dollars	December 31 2015	December 31 2014
Maturity within 1 year	$ 20.0	$ 12.8
Maturity in 1-5 years	26.3	26.1
	$ 46.3	$ 38.9

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.

24. GOODWILL

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

millions of Canadian dollars		**2015**		2014
Balance, January 1	**$**	**221.5**	$	206.5
Impairment (1)		**-**		(3.3)
Change in foreign exchange rate		**42.6**		18.3
Balance, December 31	**$**	**264.1**	$	221.5

(1) No goodwill impairment was recorded in 2015. Emera recorded a goodwill impairment charge of $3.3 million in "Operating, maintenance, and general" on the Consolidated Statements of Income during the fourth quarter of 2014. Emera determined that the operating environment, conditions and performance of the Newfoundland division of Emera Utility Services Inc. could no longer support the related goodwill balance.

25. OTHER LONG-TERM ASSETS

Other long-term assets consisted of the following:

As at millions of Canadian dollars		**December 31 2015**		December 31 2014
Subscription receipts (1)	**$**	**-**	$	111.7
Deferred debt financing (2)		**70.8**		23.0
Capitalized transportation capacity		**38.7**		31.8
Open Hydro investment		**10.0**		10.0
Equipment financing receivable		**28.7**		20.5
Other		**18.1**		8.3
	$	**166.3**	$	205.3

(1) In Q4 2015, Emera reclassified outstanding subscription receipts from "Other long-term assets" to Investments subject to significant influence as they became eligible for conversion into APUC common shares.
(2) As at December 31, 2015, the deferred debt financing asset includes $46.2 million related to the $2.185 billion in Debentures to finance a portion of the pending TECO Energy acquisition. The deferred debt financing costs related to the Debentures are being amortized over 10 years, the contractual term of the debentures, in Interest expense, net.

26. SHORT-TERM DEBT

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

millions of Canadian dollars		**2015**	**Weighted-average interest rate**		2014	Weighted-average interest rate
NSPI						
Bank indebtedness		**15.9**	**2.70 %**		2.3	3.00 %
GBPC						
Bank indebtedness		**-**	**-**		0.1	5.75 %
Emera Energy						
Advances on the non-revolving credit facilities		**-**	**-**		255.2	1.36 %
Short-term debt	**$**	**15.9**		$	257.6	

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

millions of Canadian dollars	Maturity	**2015**	2014
GBPC - revolving credit facility	2016	**18.0**	15.1
Emera Energy - non-revolving credit facility (1)	2014	**-**	255.2
Total		**18.0**	270.3
Less:			
Advances under revolving credit facilities		**-**	255.3
Use of available facilities		**-**	255.3
Available capacity under existing agreements		**$ 18.0**	$ 15.0

(1) Emera Energy's non-revolving credit facility was repaid in 2015.

The weighted average interest rate on outstanding short-term debt at December 31, 2015 was 2.70 per cent (2014 – 1.40 per cent).

Credit Facilities

For the purpose of bridge financing for the pending acquisition of TECO Energy, on September 4, 2015, the Company secured an aggregate of US$6.5 billion non-revolving term credit facilities the ("Acquisition Credit Facilities") from a syndicate of banks. The non-revolving term credit facilities are comprised of a US$4.3 billion debt bridge facility, repayable in full on the first anniversary following its advance, and a US$2.2 billion equity bridge facility repayable in full on the first anniversary following its advance.

Emera is required to effect reductions or make prepayments of the Acquisition Credit Facilities in an amount equal to the net cash proceeds from any common equity, preferred equity, bond or other debt offerings and any nonordinary course asset sales by Emera and its subsidiaries, subject to certain prescribed exceptions and certain other prescribed transactions. Net proceeds from any such offerings, including the net proceeds of the final instalment under the Offering, or from any such non-ordinary course asset sales or transactions, will be applied to permanently reduce the commitments of the lenders under the Acquisition Credit Facilities or to repay the Acquisition Credit Facilities after they are drawn. On October 16, 2015, Emera permanently reduced the USD bridge facilities in the amount of $588.3 million USD with the proceeds of the first instalment of the convertible debentures and the proceeds from the Bear Swamp financing.

The credit agreements pursuant to which the Acquisition Credit Facilities will be extended (the "Acquisition Credit Agreements") will contain certain prepayment options in favour of Emera and certain prepayment obligations upon the occurrence of certain events. In particular, the net proceeds of any equity or debt offering by Emera and certain of its subsidiaries (other than certain permitted equity or debt offerings subject to certain prescribed exceptions) and of any non-ordinary course asset sales (subject to certain prescribed exceptions) and certain other prescribed transactions will be required to be used to prepay the Acquisition Credit Facilities and any prepayment under the Acquisition Credit Facilities may not be re-borrowed. The Acquisition Credit Agreements will contain customary representations and warranties and affirmative and negative covenants of Emera that will closely resemble those in Emera's existing revolving credit facility.

Emera has recognized the costs associated with the bridge fees related to the Acquisition Credit Facilities in "Operating, maintenance and general" on Emera's Consolidated Statements of Income.

27. OTHER CURRENT LIABILITIES

Other current liabilities consisted of the following:

As at millions of Canadian dollars		**December 31 2015**		December 31 2014
Accrued charges	**$**	**130.1**	$	114.1
Accrued interest on long-term debt		**44.1**		42.4
Accrued interest on convertible debentures represented by instalment receipts		**11.2**		-
Emission credits obligations (1)		**6.3**		20.6
Sales taxes payable		**4.2**		5.6
Other		**8.4**		4.1
	$	**204.3**	$	186.8

(1) Throughout the three-year compliance period associated with the Regional Greenhouse Gas Initiative for carbon dioxide emissions, an obligation is recognized as gas is burned, measured at the cost to acquire credits for the related emissions. Emission credits are recorded as inventory (note 14) when purchased and subsequently applied against the emission liabilities at the end of each compliance period.

28. 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 (1)	Effective Interest Rate (2)	Maturity		2015		2014
Emera							
Bankers acceptances, LIBOR loans (3)	-	2.00%	2020	**$**	**239.5**	$	437.2
Medium-term notes							
Series G	4.83%	4.89%	2019		**225.0**		225.0
Series H	2.96%	3.05%	2016		**250.0**		250.0
					475.0		475.0
Promissory note	-	-	2016		**0.3**		0.6
Capital lease obligations	-	-	Various		**-**		0.2
				$	**714.8**	$	913.0
NSPI							
Commercial paper (4)	-	0.85%	2020	**$**	**369.3**	$	349.1
Medium-term notes							
Series F	8.85%	8.21%	2025		**125.0**		125.0
Series I	8.40%	8.43%	2015		**-**		70.0
Series L	8.30%	8.88%	2036		**60.0**		60.0
Series M (5)	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 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**		250.0
Series Z	4.50%	4.57%	2043		**300.0**		300.0
Series AA	3.61%	3.65%	2045		**175.0**		-
					1,965.0		1,860.0
Debentures – Series 3	9.75%	9.99%	2019		**95.0**		95.0
Capital lease obligations	-	4.3% & 4.8%	2016 & 2019		**0.5**		1.0
				$	**2,429.8**	$	2,305.1
Emera Maine (6)							
LIBOR loans and demand loans (7)	-	1.71%	2019	**$**	**31.7**	$	28.7
General & refunding mortgage bonds (8)							
$20 million	8.98%	8.98%	2022		**27.7**		23.2
$30 million	10.25%	10.25%	2020		**41.5**		34.8
					69.2		58.0
Senior unsecured notes							
$50 million(9)	5.31%	5.31%	2018		**18.9**		21.1
$20 million	5.87%	5.87%	2017		**27.7**		23.2
$110 million	4.34%	4.34%	2044		**152.2**		127.6
$70 million	3.61%	3.61%	2022		**96.9**		81.2
					295.7		253.1
				$	**396.6**	$	339.8
EBP							
$250 million	3.08%	3.08%	2019	**$**	**248.5**	$	-
				$	**248.5**	$	-
GBPC (6)							
Unsecured notes	3.44%	3.44%	2022	**$**	**23.9**	$	23.3
Unsecured notes	3.70%	3.70%	2021		**52.5**		50.6
Bond notes	6.96%	6.96%	2020		**30.4**		25.5
Bond notes	7.16%	7.16%	2023		**38.8**		32.5
				$	**145.6**	$	131.9

BLPC & ECI					
Senior secured notes					
$19.2 million (10)	6.50%	7.00%	2021	**$ 10.8**	$ 10.1
$20 million (10)	6.65%	6.65%	2020	**13.8**	11.6
$20 million (10)	6.88%	6.88%	2025	**13.8**	11.6
$2.0 million (11)	5.99%	5.99%	2015	**-**	1.2
$7.1 million (6)(12)	2.37%	2.37%	2015	**-**	2.8
$10.1 million (6)(12)	4.31%	4.31%	2028	**12.0**	10.9
$50.5 million (13)	5.75%	5.75%	2021	**16.2**	15.7
$16.0 million (6)	4.50%	4.58%	2020	**22.5**	-
Other				**0.3**	0.5
				$ 89.4	$ 64.4
Adjustments					
Unamortized debt premium - net				**0.1**	0.6
Amount due within one year				**(274.0)**	(94.5)
				$ (273.9)	$ (93.9)
Long-Term Debt				**$ 3,750.8**	$ 3,660.3

(1) The stated interest rate is the coupon rate for any long term debt issuance.
(2) The effective interest rate is the constant rate which will fully amortize the premium/discount and issuance costs over the life of the associated debt when the rate is applied against the net amount of debt less unamortized costs.
(3) Emera's revolving credit facility matures in June 2020, 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.
(4) NSPI's commercial paper is backed by a revolving credit facility, which matures in 2020.
(5) Note is extendable until 2056 at the option of the holders.
(6) Debt issued and payable in USD.
(7) Emera Maine's revolving credit facility matures in September 2019, at which point the Company has the intention to renew under similar terms.
(8) Secured by property, plant and equipment of Emera Maine.
(9) Sinking fund payments began in 2008.
(10) 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.
(11) 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.
(12) Cash security in the form of security deposit.
(13) Issued and payable in East Caribbean dollars. Fixed charge over property of Domlec.

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	**2015**	2014
Emera – revolving credit facility (1)	June 2020	**$ 700.0**	$ 700.0
NSPI - revolving credit facility (1)	October 2020	**500.0**	500.0
Emera Maine – revolving credit facility	September 2019	**110.7**	92.8
BLPC – revolving credit facility	2017-2021	**26.3**	22.0
Total		**1,337.0**	1,314.8
Less:			
Borrowings under credit facilities		**641.3**	816.2
Letters of credit issued inside credit facilities		**33.1**	13.4
Use of available facilities		**674.4**	829.6
Available capacity under existing agreements		**$ 662.6**	$ 485.2

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $50 million.

Credit Facilities

NSPI

On April 30, 2015, NSPI completed the issuance of $175 million Series AA Medium-Term Notes ("MTN"). The Series AA notes bear interest at a rate of 3.612 per cent per annum until May 1, 2045. The proceeds of the note offering were used for general corporate purposes, including the repayment of maturing corporate term debt.

NSPI Series I $70 million 8.40 per cent MTN matured on October 23, 2015.

Brunswick Pipeline

On February 18, 2015, Brunswick Pipeline completed a senior secured financing consisting of a $250 million non-revolving term credit facility bearing interest at bankers' acceptances rates plus 1.75 per cent and expiring on February 18, 2019. The proceeds were used to reduce borrowings under Emera's revolver, which was previously used to finance the maturity and repayment of a MTN note in October 2014.

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, 2015
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.51:1

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	2016	2017	2018	2019	2020	Greater than 5 years	Total
Emera	**$** 250.3	$ -	$ -	$ 225.0	$ 239.5	$ -	$ 714.8
NSPI	0.3	0.1	0.1	95.0	369.3	1,965.0	2,429.8
EBP	-	-	-	248.5	-	-	248.5
Emera Maine	6.3	34.0	6.3	31.7	41.5	276.8	396.6
GBPC	11.8	11.8	11.8	11.8	42.2	56.2	145.6
BLPC	5.3	7.1	7.3	7.6	36.2	25.6	89.1
Total	**$** 274.0	$ 53.0	$ 25.5	$ 619.6	$ 728.7	$ 2,323.6	$ 4,024.4

29. 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 and a pipeline site. 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.

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

millions of Canadian dollars	**2015**	2014
Balance, January 1	**$ 106.2**	$ 98.6
Liabilities settled	**(1.5)**	(1.4)
Accretion included in depreciation expense	**7.6**	7.6
Accretion deferred to regulatory asset (included in property, plant and equipment)	**(2.4)**	(2.4)
Revisions in estimated cash flows	**4.1**	3.6
Change in foreign exchange rate	**0.7**	0.2
Balance, December 31	**$ 114.7**	$ **106.2**

As at December 31, 2015 and 2014, 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.

30. CONVERTIBLE DEBENTURES REPRESENTED BY INSTALMENT RECEIPTS

To finance a portion of the pending acquisition of TECO Energy, Emera, through a direct wholly owned subsidiary (the "Selling Debentureholder"), on September 28, 2015, completed the sale of $1.9 billion aggregate principal amount of 4.0% convertible unsecured subordinated debentures, represented by instalment receipts (the "Debentures" or the "Debenture Offering").

On October 2, 2015, in connection with the Debenture Offering, the underwriters fully exercised an over-allotment option and purchased an additional $285 million aggregate principal amount of Debentures at the Debenture Offering price. The sale of the additional Debentures brought the aggregate proceeds of the Debenture Offering to $2.185 billion, assuming payment of the final instalment.

The Debentures were sold on an instalment basis at a price of $1,000 per Debenture, of which $333 was paid on closing of the Debenture Offering and the remaining $667 (the "Final Instalment") is payable on a date ("Final Instalment Date") to be fixed following satisfaction of conditions precedent to the closing of the acquisition of TECO Energy.

Prior to the Final Instalment Date, the Debentures are represented by instalment receipts. The instalment receipts began trading on the Toronto Stock Exchange ("TSX") on September 28, 2015 under the symbol "EMA.IR". The Debentures will not be listed. The Debentures will mature on September 29, 2025 and bear interest at an annual rate of four per cent per $1,000 principal amount of Debentures until and including the Final Instalment Date, after which the interest rate will be 0 per cent. Based on the first instalment of $333 per $1,000 principal amount of Debentures, the effective annual yield to and including the Final Instalment Date is 12 per cent, and the effective annual yield thereafter is 0 per cent.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Debenture Offering had the Debentures remained outstanding and continued to accrue interest until and including such date (the "Make-Whole Payment"). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Debenture Offering. Under the terms of the instalment receipt agreement, Emera agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Company will at all times hold (on a consolidated basis) short-term USD investment grade securities or have cash on hand of not less than the aggregate amount of the first instalment paid on the closing of the Debenture Offering and the exercise of the over-allotment option, in the event of a mandatory redemption.

At the option of the holders and provided that payment of the Final Instalment has been made, each Debenture will be convertible into common shares of Emera at any time after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $41.85 per common share. This is a conversion rate of 23.8949 common shares per $1,000 principal amount of Debentures, subject to adjustment in certain events.

Prior to the Final Instalment Date, the Debentures may not be redeemed by the Company, except that Debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions precedent to the closing of the acquisition of TECO Energy will not be satisfied; (ii) termination of the acquisition agreement; and (iii) April 24, 2017, if notice of the Final Instalment Date has not been given to holders on or before April 21, 2017. Upon any such redemption, the Company will pay for each Debenture: (i) $333 plus accrued and unpaid interest to the holder of the instalment receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the instalment receipt in satisfaction of the Final Instalment. In addition, after the Final Instalment Date, any Debentures not converted may be redeemed by Emera at a price equal to their principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date.

At maturity, Emera will repay the principal amount of any Debentures not converted and remaining outstanding in cash. Emera has the right to satisfy the obligation to repay the principal amount due in common shares, which will be valued at 95 per cent of the weighted-average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

The proceeds of the first instalment and the overallotment of the Debenture Offering were $727.6 million, or $681.4 million net of issue costs, and are held and invested in short-term USD investment grade securities. The convertible debentures represented by instalment receipts are classified as a current liability on the Consolidated Balance Sheets as the pending acquisition of TECO Energy is expected to close in fiscal 2016. The mark-to-market effect related to the translation of the US foreign currency to Canadian currency is recorded in income, but not reflected in adjusted net income.

The net proceeds of the final instalment payment of the Debenture Offering are expected to be, in aggregate, approximately $1.4 billion and will be used, together with the net proceeds of the first instalment payment, to finance, directly or indirectly, the pending acquisition of TECO Energy and other acquisition related costs. To mitigate the foreign currency translation risk associated with the final instalment Emera entered into USD denominated forward contracts, which are recorded on the Consolidated Balance Sheets. The mark-to-market effect on these hedges is reported in the income statement and impacts income, but is not reflected in adjusted income.

Approximately $22.1 million ($15.2 million after-tax) in interest expense associated with the Debentures was recognized in Q4 2015 and $22.7 million ($15.7 million after-tax) was incurred during fiscal 2015 (2014 – nil) (note 8).

31. OTHER LONG-TERM LIABILITIES

Other long-term liabilities consisted of the following:

As at millions of Canadian dollars	**December 31 2015**	December 31 2014
Funds received in excess of equity investment (1)	**$ 225.0**	$ 20.8
Long-term service agreements	**37.7**	-
Hydro-Quebec obligation	**7.6**	6.8
Emission credits obligations (2)	**6.3**	-
Other	**21.9**	20.7
	$ 298.5	$ 48.3

(1) Emera has a 50 per cent investment in Bear Swamp. As at December 31, 2015 and 2014, the investment balance in Bear Swamp was a credit. The 2015 and 2014 balances have been restated. The credit investment balance is primarily a result of a $178.7 million distribution received in Q4 2015.
(2) Throughout the three-year compliance period associated with the Regional Greenhouse Gas Initiative for carbon dioxide emissions, an obligation is recognized as gas is burned, measured at the cost to acquire credits for the related emissions. Emission credits are capitalized to inventory (note 14) when purchased and subsequently applied against the emission liabilities at the end of each compliance period.

32. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2015, contractual commitments (excluding pensions and other post-retirement obligations, convertible debentures represented by instalment receipts, long-term debt and AROs) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2016	2017	2018	2019	2020	Thereafter	Total
Purchased power (1)	$ 221.7	$ 235.0	$ 208.6	$ 203.1	199.4	$ 2,462.8	$ 3,530.6
Coal, biomass, oil and natural gas supply	150.2	82.1	12.2	-	-	-	244.5
DSM (2)	24.7	34.0	34.9	-	-	-	93.6
Transportation (3)	183.6	72.2	55.8	25.7	20.9	86.9	445.1
Long-term service agreements (4)	56.6	45.0	33.6	55.7	18.4	207.1	416.4
Capital projects	68.9	7.1	-	-	-	-	76.0
Equity investment commitments (5)	379.6	159.0	-	-	-	-	538.6
Leases and other (6)	12.6	11.6	9.5	8.9	7.5	27.5	77.6
	$ 1,097.9	$ 646.0	$ 354.6	$ 293.4	$ 246.2	$ 2,784.3	$ 5,422.4

(1) Purchased power: annual requirement to purchase 20 - 100 per cent of electricity production from independent power producers over varying contract lengths up to 25 years.

(2) DSM: program is expected to continue however no amounts have been committed after 2018.

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

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

(5) Emera has a commitment in connection with the Federal Loan Guarantee ("FLG") to complete construction of the Maritime Link. Thirty per cent of the financing of this project will come from Emera as equity. Emera also has a commitment to make equity contributions to the Labrador Island Link Limited Partnership upon draw requests from the general partner. The amounts forecasted are a combination of equity investments for both projects and are subject to change in both timing and amounts as the projects advance through construction.

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

B. Legal Proceedings

Emera

Between September 16, 2015 and November 2, 2015, purported shareholders of TECO Energy filed twelve separate complaints styled as class action lawsuits in the Circuit Court for the 13th Judicial Circuit, in and for Hillsborough County, Florida or the United States District Court for the Middle District of Florida (the “Merger Litigation”). Each complaint alleges, among other things, that the Board of Directors of TECO Energy breached its fiduciary duties in agreeing to the acquisition agreement and that Emera and/or Emera US Inc. aided and abetted such alleged breaches. The complaints seek to enjoin the merger pursuant to the acquisition agreement.

On November 17, 2015, TECO Energy, Emera, Emera US Inc. and the Board of Directors of TECO Energy entered into a memorandum of understanding with the shareholder plaintiffs to settle all of the Merger Litigation, subject to negotiation of a stipulation of settlement with the plaintiffs and to court approval. The memorandum of understanding provides for all claims against the defendants to be released in exchange for TECO Energy making certain additional disclosures to its shareholders related to the proposed merger (which have now been made).

There is no assurance that the parties will ultimately enter into a stipulation of settlement or that the court will approve the settlement even if the parties were to enter into a stipulation of settlement.

Emera Maine

On September 30, 2011, a group including the Attorney General of Massachusetts, New England utilities commissions, state public advocates and end users filed a complaint with the Federal Energy Regulatory Commission ("FERC") alleging that the 11.14 per cent base return on equity ("ROE") under the ISO-New England (ISO-NE) Open Access Transmission Tariff ("OATT") was unjust and unreasonable. On June 19, 2014, the FERC issued an order in connection with this complaint, changing the methodology used to set the ROE for transmission assets.

This change would lower the base transmission ROE to 10.57 per cent for the period of October 1, 2011 to December 31, 2012, subject to a further proceeding to finalize the determination of appropriate rates to be used in such calculation. The FERC decision would also lower the cap on the total ROE (inclusive of incentive adders) for transmission assets to 11.74 per cent. In an order issued on October 16, 2014, the FERC confirmed that the ROE set in its earlier order was appropriate. On March 3, 2015, in response to requests for rehearing from several parties, FERC affirmed its initial Order, setting of the base ROE of 10.57 per cent and capping the total ROE, including the effect of incentive adders, at 11.74 per cent. Notices of Appeal to the U.S. Court of Appeals for the DC Circuit were filed by New England Transmission Owners and the Complainants in the case on April 30, 2015. In Q2 2015, Emera Maine began processing the refunds to customers, based on a 10.57 per cent ROE. By court order dated August 20, 2015, the DC Court of Appeals decided to hold the appeal of this case in abeyance pending the outcome of the consolidated cases ("ENE Case" and "MA AG II Case") discussed below.

On December 27, 2012, a second group of consumer advocates, including Environment Northeast, filed a complaint with the FERC on similar grounds, arguing that the 11.14 per cent base ROE under the OATT was unjust and unreasonable ("the ENE Case"). On June 19, 2014, the FERC issued an order in this second ROE case, finding in favour of the complainants and allowing the complaint to proceed. As a result, a new ROE will be calculated and set by the FERC. This complaint created a new 15-month refund period beginning January 1, 2013 through March 31, 2014.

On July 31, 2014, a group of state commissions, state public advocates and end users filed a third complaint with the FERC alleging the ROE earned on transmission investments is unjust and unreasonable and does not reflect current economic conditions ("the MA AG II Case"). Any potential refund arising from this third complaint will relate to the period from July 31, 2014 to September 30, 2015, and the outcome will set the ROE going forward from the date of decision.

On November 24, 2014, the FERC consolidated the ENE Case and MA AG II Case. A subsequent order by the FERC established a schedule for various procedural matters that turned the case over to an Administrative Law Judge in September 2015. Once that judge's recommended decision is rendered, parties may file exceptions, and then the case is set for decision by the FERC. A decision is therefore not expected until Q1 2016 at the earliest.

Emera Maine has recorded a reserve of $6.9 million pre-tax ($5.0 million USD) (2014 - $8.5 million) for the base transmission ROE rate refund complaints for the period of October 1, 2011 to May 31, 2015. The reserves recorded for these complaints have been recorded as a component of Regulatory Liabilities on the Consolidated Balance Sheets, and the charges to earnings have been a reduction to Operating revenues - regulated on the Consolidated Statements of Income.

Other Legal Proceedings

Emera and its subsidiaries may, from time to time, be involved in other legal proceedings, claims and litigation 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 will be approximately $43.2 million during fiscal 2015 and are estimated to be $63.9 million from 2016 through 2019. Amounts that have been committed to are included in "Capital projects" in the commitments table in note 32A. The estimated expenditures do not include costs related to possible changes in the environmental laws or regulations and enforcement policies that 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 internal requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the audits completed to December 31, 2015.

Emera Energy Emissions

The New England Gas Generating Facilities are subject to the Regional Greenhouse Gas Initiative ("RGGI") for carbon dioxide emissions and the Acid Rain Program for sulphur dioxide emissions. The New England Gas Generating Facilities emit approximately two million tons of carbon dioxide per year. The amount of sulphur dioxide emitted is not considered significant. Changes to these emissions programs could adversely impact financial and operational performance.

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 the end of 2025. This also includes PCB contaminated pole mounted transformers. The combined total cost of these projects is estimated to be $40.1 million and, as at December 31, 2015, approximately $19.7 million (December 31, 2014 – $14.8 million) has been spent to date. NSPI has recognized an ARO of $15.0 million as at December 31, 2015 (December 31, 2014 – $11.8 million) associated with the PCB phase-out program.

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 and Political Risk

The Company's rate-regulated subsidiaries and certain investments subject to significant influence are subject to risk of the recovery of costs and investments in a timely manner. As cost-of-service utilities with an obligation to serve, NSPI, Emera Maine, BLPC, GBPC and Domlec 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 or may be mandated by other governmental bodies. In addition, the commercial and regulatory frameworks under which Emera and its subsidiaries operate can be impacted by significant shifts in government policy and changes in governments. Emera has certain investments subject to significant influence that are subject to regulatory risk and include: APUC, M&NP, NSPML, LIL and Lucelec.

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. In some circumstances, other government bodies may influence the setting of rates. The subsidiaries manage this regulatory risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, fuel-related audits, rate filings and capital plans. The subsidiaries employ a collaborative regulatory approach through technical conferences and, where appropriate, negotiated settlements.

In November 2014, the Federal Energy Regulatory Commission ("FERC") commenced an audit covering the 2013 and 2014 period of Bangor Hydro Electric Company's ("BHE") compliance with conditions established in FERC's orders authorizing its acquisition of Maine Public Service Company ("MPS"), which occurred on January 1, 2014. These two predecessor companies formed Emera Maine. The final audit report was released in early January 2016. The findings in the audit report conclude that Emera Maine did not follow the prescribed methodology for the calculation of AFUDC during the audit period and Emera Maine had included, in rates, costs of the BHE and MPS merger prior to making the required filings. Emera Maine will fully comply with the recommendations in the audit report, including making the required filings for the merger costs and recalculating AFUDC for 2013 and 2014, as ordered, which resulted in an immaterial impact on the Company's Consolidated Statements of Income.

Brunswick Pipeline entered into a 25-year firm service agreement with Repsol Energy Canada, which was filed with the 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 Brunswick Pipeline are regulated by the NEB on a complaint basis. Brunswick Pipeline 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 Brunswick Pipeline may file a complaint with the NEB. In the absence of a complaint, the NEB does not normally undertake a detailed examination of Brunswick Pipeline's tolls.

Changes in Environmental Legislation

Emera is subject to regulation by federal, provincial, state, regional and local authorities with regard to environmental matters; primarily related to its utility operations. This includes laws setting greenhouse gas emissions standards and air emissions standards. Emera is also subject to laws regarding the generation, storage, transportation, use and disposal of hazardous substances and materials.

In addition to imposing continuing compliance obligations, there are permit requirements, laws and regulations 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, and may be, material to Emera. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on Emera.

New emission reductions requirements for the utilities sector are being established by governments in Canada and the United States. Changes to greenhouse gas emissions standards and air emissions standards could adversely affect Emera's operations and financial performance. Stricter environmental laws and enforcement of such laws in the future could increase Emera's exposure to additional liabilities and costs. These changes could also affect earnings and strategy by changing the nature and timing of capital investments.

Emera manages its environmental risk by operating in a manner that is respectful and protective of the environment and with the objective of achieving full compliance with applicable laws, legislation and company policies and standards. Emera has implemented this policy through the development and application of environmental management systems in its operating subsidiaries. Comprehensive audit programs are also in place to regularly test compliance with such laws, policies and standards.

Commercial Relationships

The Company is exposed to commercial relationship risk in respect of its reliance on certain key partners, supplies and customers. The company manages its commercial relationship risk by monitoring credit risk, and monitoring of significant developments with its customers, partners and suppliers.

ENL

Emera and Nalcor Energy executed agreements pertaining to the development and transmission of hydroelectric power from Muskrat Falls in Labrador to the island of Newfoundland, the Province of Nova Scotia and through to New England. In exchange for the Company's investment in the Maritime Link Project, estimated to be approximately $1.56 billion, Nalcor has agreed to provide 20 per cent of the output of the Muskrat Falls generating station.

Labour Risk

Certain Emera employees are subject to collective labour agreements; 49 per cent of the full-time and term employees within the Emera group of companies are represented by local unions.

Approximately 7 per cent of Emera's work force is included in collective labour agreements which will expire within the next 12 months.

Interest Rate Risk

The Company utilizes a combination of fixed and floating 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.

For the Company's regulated subsidiaries, the cost of debt is generally passed through to ratepayers. While regulatory ROE rates will generally and indirectly follow the direction of interest rates, regulatory ROE's are likely to fall in times of reducing interest rates and raise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development initiatives.

The Company is subject to interest rate risk relating to certain sources of expected funds to effect the TECO Energy acquisition. Any movement in interest rates could affect the underlying cost of the instrument used to fund the acquisition. The Company may enter into interest rate hedging contracts to limit its exposure to fluctuations in interest rates.

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 regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs.

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.

The cash consideration for the TECO Energy acquisition is required to be paid in US dollars, a portion of which will be raised in Canadian dollars. As a result, increases in the value of the US dollar versus the Canadian dollar will increase the purchase price translated in Canadian dollars and thereby increase the Canadian dollars required to fund the USD purchase price for the acquisition ultimately obtained by the Company.

The proceeds of the first instalment of the Debenture Offering were invested in short-term US dollar investment grade securities.

During the month of October 2015, Emera entered into foreign exchange forward contracts to economically hedge an amount equal to the anticipated proceeds from the second instalment of the Debenture Offering of the pending TECO Energy acquisition of $1.457 billion. These foreign exchange forward contracts are economic hedges and do not qualify for hedge accounting. Therefore, all mark-to-market gains and losses will be recognized in net income for the period. In addition, the operations of TECO Energy are conducted in US dollars. Following the acquisition, the consolidated net income of Emera will be impacted to a greater extent by movements in the US dollar relative to the Canadian dollar.

E. Guarantees and Letters of Credit

Emera had outstanding the following guarantees and letters of credit on behalf of third parties which are not included within the Consolidated Balance Sheets as at December 31, 2015:

- Emera has provided a completion guarantee to the Government of Canada, whereby it has guaranteed the performance of the obligations of NSPML to cause the completion of the Maritime Link Project, subject to certain conditions set out in that guarantee. The cost of those obligations is estimated to be $1.577 billion, which reduces in the ordinary course as project costs are paid.

- 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 per cent of the relevant obligations under the PPA up to a maximum of $5.1 million USD. As at December 31, 2015, the fair value of the PPA was positive.

- Standby letters of credit in the amount of $20.5 million USD for the benefit of secured parties in connection with a refinancing of the Bear Swamp joint venture and also to third parties that have extended credit to Emera and its subsidiaries. These letters of credit typically have a one-year term and are renewed annually as required.

- A standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2016 and is renewed annually. The amount committed as at December 31, 2015 was $42.6 million.

- A standby letter of credit to secure obligations under an unfunded pension plan in Emera Maine. The letter of credit expires in October 2016 and is renewed annually. The amount committed as at December 31, 2015 was $2.7 million USD.

- A standby letter of credit was issued to secure the obligations of Emera Reinsurance Limited under reinsurance agreements. The letter of credit expires in February 2016. The amount committed as at December 31, 2015 was $2.0 million USD.

F. Collaborative Arrangements

NSPI

Through NSPI, the Company is a participant in a 23.3 megawatt (“MW”) wind energy project with Renewable Energy Services Ltd. in Point Tupper, Nova Scotia. Percentage ownership of the wind project assets is based on the relative value of each party’s project assets by the total project assets with NSPI owning 47.4 per cent. NSPI has a power purchase arrangement to purchase the entire net output of the project and, therefore, NSPI’s portion of the revenues are recorded net, within regulated fuel for generation and purchased power. NSPI’s portion of operating expenses are recorded in operating, maintenance and general (“OM&G”) expenses. In 2015, NSPI recognized $2.8 million net expense (2014 – $3.0 million) in “Regulated fuel for generation and purchased power” and $0.5 million (2014 – $0.5 million) in “OM&G”. As part of this arrangement, NSPI received a portion of an Eco Energy revenue claim totaling $0.3 million in 2015.

Through NSPI, the Company is a participant in a 102 MW wind energy project with South Canoe Development Partnership for South Canoe Wind Farm, in New Ross, Nova Scotia. Percentage ownership of the wind project assets is based on the relative value of each party’s project assets by the total project assets, with NSPI owning not more than 49 per cent. NSPI has a power purchase arrangement to purchase the entire net output of the project and therefore NSPI’s portion of the revenues are recorded net, within “Regulated fuel for generation and purchased power”. NSPI’s portion of operating expenses, are recorded in “OM&G”. The project went reached commercial operation in Q2 2015. In 2015, NSPI recognized a $6.4 million net expense in “Regulated fuel for generation and purchased power” and $1.1 million in “OM&G”.

Through NSPI, the Company is a participant in a 13.8 MW wind energy project with Municipality of the District of Guysborough for Sable Wind Farm, near Canso, Nova Scotia. Percentage ownership of the wind farm will be based on the relative value of each party’s project assets by the total project assets, with NSPI owning not more than 49 per cent. NSPI’s has a power purchase arrangement to purchase the entire net output of the project and therefore NSPI’s portion of the revenues are recorded net, within “Regulated fuel for generation and purchased power”. NSPI’s portion of operating expenses, are recorded in “OM&G”. The project went reached commercial operation in Q2 2015. In 2015, NSPI recognized a $1.0 million net expense in “Regulated fuel for generation and purchased power” and $0.1 million in “OM&G”.

Emera Maine

Through Emera Maine, 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. Emera Maine has deferred $4.6 million ($3.3 million USD) of costs associated with the NEL project as at December 31, 2015 (December 31, 2014 – $3.6 million), reported in the Consolidated Balance Sheets in “Other” as part of “Other long-term assets”.

Through Emera Maine, the Company is a party to a collaborative arrangement with EDP Renewables ("EDPR"), Central Maine Power (“CMP”) and Maine Electric Power Company Inc. (“MEPCO”) related to construction of an electric transmission line in Northern Maine. Emera Maine and CMP retain an option to buy-back the transmission line as part of a larger solution to collect further quantities of wind generation being pursued for development in Northern Maine, for delivery into the ISO-NE market. CMP and Emera Maine agreed to pursue this regional solution together per a Memorandum of Understanding ("MOU") signed in May 2014. As at December 31, 2015, Emera Maine had deferred $1.4 million ($1.0 million USD) (December 31, 2014 – $1.2 million) associated with this development.

33. COMMON STOCK

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

Issued and outstanding:	2015 millions of shares	2015 millions of Canadian dollars	2014 millions of shares	2014 millions of Canadian dollars
Balance, January 1	**143.78**	**$ 2,016.4**	132.89	$ 1,703.0
Issuance of common stock (1)	**1.25**	**53.7**	8.66	242.8
Issued for cash under Purchase Plans at market rate	**2.10**	**88.3**	1.97	66.6
Discount on shares purchased under Dividend Reinvestment Plan	**-**	**(4.1)**	-	(3.0)
Options exercised under senior management share option plan	**0.08**	**2.3**	0.26	6.2
Employee Share Purchase Plan	**-**	**0.9**	-	0.8
Balance, December 31	**147.21**	**$ 2,157.5**	143.78	$ 2,016.4

(1) On December 17, 2015, Emera issued 1.25 million common shares to facilitate the creation and issuance of 5.0 million depositary receipts in connection with the ECI share acquisition. The depositary receipts are listed on the Barbados Stock Exchange.

As at December 31, 2015, there were the following common shares reserved for issuance: 7.3 million (2014 – 7.3 million) under the senior management stock option plan, 1.6 million (2014 – 1.8 million) under the employee common share purchase plan and 3.3 million (2014 – 5.2 million) under the dividend reinvestment plan. The issuance of common shares under the current or proposed common share compensation arrangements will not exceed ten per cent of Emera's outstanding common shares. As at December 31, 2015, Emera is in compliance with this requirement.

34. CUMULATIVE PREFERRED STOCK

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

			December 31, 2015		December 31, 2014	
	Annual Dividend Per Share	Redemption Price per share	**Issued and Outstanding**	**Net Proceeds**	Issued and Outstanding	Net Proceeds
Series A	$ 0.6388	$ 25.00	**3,864,636**	**$ 94.5**	6,000,000	$ 146.7
Series B	Floating	$ 25.00	**2,135,364**	**$ 52.2**	-	$ -
Series C	$ 1.0250	$ 25.00	**10,000,000**	**$ 244.9**	10,000,000	$ 244.9
Series E	$ 1.1250	$ 26.00	**5,000,000**	**$ 122.4**	5,000,000	$ 122.4
Series F	$ 1.0625	$ 25.00	**8,000,000**	**$ 195.5**	8,000,000	$ 195.5

On August 17, 2015, Emera announced that 2,135,364 of its 6,000,000 issues and outstanding Series A Shares were tendered for conversion, on a one-for-one basis into Cumulative Floating Rate First Preferred Shares, Series B (the “Series B Shares”). As a result of the conversion, Emera has 3,864,636 Series A Shares and 2,135,364 Series B Shares issued and outstanding. The 2015 dividends for the Series A and Series B shares were $0.98470 and $0.15080 respectively.

The First Preferred Shares, Series A, C and F are entitled to receive fixed cumulative cash dividends as and when declared by the Board of Directors of the Corporation in the amounts of $0.6388, $1.025 and $1.0625 per share per annum, respectively for each year up to and excluding August 15, 2020, August 15, 2018, and February 15, 2020, respectively. As at August 15, 2020, August 15, 2018, and February 15, 2020, the holders of the First Preferred Shares Series A, C and F, respectively, are entitled to receive reset fixed cumulative cash dividends. The reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate of the First Preferred Shares, Series A, C and F, respectively, which is the sum of the five-year Government of Canada Bond Yield on the application reset date plus 1.84 per cent, 2.65 per cent, and 2.63 per cent, respectively.

The First Preferred Shares, Series B, are entitled to receive floating rate cumulative cash dividends, as and when declared by the Board of Directors in the amount determined by multiplying $25.00 by the three month Government of Canada Treasury Bill rate plus 1.84 per cent.

The First Preferred Shares, Series E, are entitled to receive fixed rate cumulative cash dividends, as and when declared by the Board of Directors in the amount $1.1250 per annum.

The holders of First Preferred Shares, Series A, C and F will have the right, at their option, to convert their shares into an equal number of Cumulative Floating Rate First Preferred Shares, Series B, D, and G, of the Company, respectively, on August 15, 2020 August 15, 2018, and February 15, 2020, respectively, and every five years thereafter.

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.

The Company has the right to redeem the outstanding Preferred Shares, Series A, C, and F shares without the consent of the holder on August 15, 2020, August 15, 2018, and February 15, 2020 respectively and on August 15, August 15 and February 15 respectively every five years thereafter for cash, in whole or in part at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

The Company has the right to redeem the outstanding Preferred Shares, Series B, Series D and Series G shares without the consent of the holder on August 15, 2020, August 15, 2023 and February 15, 2025 respectively and on August 15, August 15 and February 15 every five years thereafter for cash, in whole or in part at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption and $25.50 per share plus all accrued and unpaid dividends on any other date after August 15, 2015, August 15, 2018 and February 15, 2020, respectively.

The Company has the right to redeem the outstanding First Preferred Shares, Series E on or after August 15, 2018 in whole or in part, at the Company's option, by the payment in cash of $26.00 per Series E Preferred Share if redeemed prior to August 15, 2019; at $25.75 per Series E Preferred Share if redeemed on or after August 15, 2019, but prior to August 15, 2020; at $25.50 per Series E Preferred Share if redeemed on or after August 15, 2020, but prior to August 15, 2021; at $25.25 per Series E Preferred Share if redeemed on or after August 15, 2021, but prior to August 15, 2022; and at $25.00 per Series E Preferred Share if redeemed on or after August 15, 2022, in each case together with all accrued and unpaid dividends up to but excluding the date fixed for redemption.

As the First Preferred Shares, Series A, B, C, E and F 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 of each series rank on a parity with the First preferred Shares of every other series and are entitled to a preference over 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.

35. NON-CONTROLLING INTEREST IN SUBSIDIARIES

Non-controlling interest in subsidiaries consisted of the following:

As at millions of Canadian dollars		**December 31 2015**		December 31 2014
ICDU	**$**	**51.8**	$	40.9
ECI (1)		**48.3**		99.6
Preferred shares of GBPC		**33.5**		33.5
Preferred shares of Emera Maine		**0.4**		0.4
Preferred shares of NSPI (2)		**-**		132.2
	$	**134.0**	$	306.6

(1) On December 17, 2015, an indirect wholly-owned subsidiary of Emera acquired approximately 2.6 million ECI shares, increasing its ownership interest from 80.7 per cent to 95.5 per cent.
(2) On October 15, 2015, NSPI redeemed all of its outstanding Cumulative Redeemable First Preferred Shares, Series D for a redemption price of $25.00 per share for a total of $135 million. The issuance costs are treated as a deemed dividend of $2.8 million, recognized when the redemption occurred on October 15, 2015.

Preferred shares of NSPI:

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

			2015			2014
Issued and outstanding:	**Millions of shares**		**Millions of dollars**	Millions of shares		Millions of dollars
Outstanding as at December 31	**-**	**$**	**-**	**5.4**	**$**	132.2

Preferred shares of GBPC:

Authorized:
35,000 non-voting cumulative redeemable variable perpetual preferred shares

			2015			2014
Issued and outstanding:	**number of shares**		**millions of dollars**	number of shares		millions of dollars
Outstanding as at December 31	**35,000**	**$**	**33.5**	35,000	$	33.5

GBPC Non–Voting Cumulative Variable Perpetual Preferred Stock:

The Preferred Stock is redeemable by GBPC, in whole at any time or in part from time to time, at $1,000 Bahamian per share plus accrued and unpaid dividends.

The Preferred Stock is entitled to a 7.25 per cent per annum fixed cumulative preferential dividend for years 2013 through 2016, 8.50 per cent per annum fixed cumulative preferential dividend for years 2017 through 2019 and 10.00 per cent per annum fixed cumulative preferential dividend after 2020, as and when declared by the Board of Directors, accruing from the date of issue.

The Preferred Shares rank behind all of GBPC's current and future secured and unsecured debt with any of GBPC's future preferred stock and ahead of all of GBPC's current and future common stock.

36. STOCK-BASED COMPENSATION

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

All employees may participate in Emera's Employee Common Share Purchase Plan to which employees make cash contributions of a minimum of $25 to a maximum of $8,000 per year for the purpose of purchasing common shares of Emera. The Company also contributes to the plan a percentage of the employees' contributions. If an employee contributes any amount up to $3,000 to employees plan account, the Company will contribute 20 per cent of that amount. When an employee contributes any amount over $3,000, up to the $8,000 maximum, the Company will contribute ten per cent of that amount.

The plan allows the reinvestment of dividends. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 4 million common shares.

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 for the purpose of purchasing common shares. The plan provides for a discount of up to 5 per cent 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.

Compensation cost for shares issued by Emera for the year ended December 31, 2015 under the Employee Common Share Purchase Plan was $0.9 million (2014 – $0.8 million) and is included in "Operating, maintenance and general" on the Consolidated Statements of Income.

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 11.7 million shares.

All options granted to date are exercisable on a graduated basis with up to 25 per cent of options exercisable on the first anniversary date and further 25 per cent 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 per cent 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 behaviour 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 five-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 five-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:

For the year ended December 31,		**2015**		2014
Weighted average fair value per option	**$**	**2.66**	$	2.25
Expected term		**5 years**		5 years
Risk-free interest rate		**0.73%**		1.68%
Expected dividend yield		**3.65%**		4.47%
Expected volatility		**14.58%**		15.77%

The following table summarizes information related to the stock options for 2015:

	Total Options			Non-Vested Options(1)		
	Number of Options	Weighted average exercise price per share		Number of Options	Weighted average grant date fair-value	
Outstanding as at December 31, 2014	2,425,493	$	30.54	1,319,421	$	2.66
Granted	581,700		42.71	581,700		2.66
Exercised	(80,125)		26.29	N/A		N/A
Vested	N/A		N/A	(447,635)		2.75
Options outstanding December 31, 2015	**2,927,068**	**$**	**33.07**	**1,453,486**	**$**	**2.64**
Options exercisable December 31, 2015(2)(3)	**1,473,582**	**$**	**29.13**			

(1) As at December 31, 2015 there was $2.5 million of unrecognized compensation related to stock options not yet vested which is expected to be recognized over a weighted average period of approximately 2.3 years (2014 - $2.4 million, 2.5 years).
(2) As at December 31, 2015, the weighted average remaining term of vested options was 5.3 years with an aggregate intrinsic value of $20.8 million (2014: 5.5 years, $12.6 million).
(3) As at December 31, 2015 the fair value of options that vested in the year was $1.2 million (2014: $1.1 million).

Compensation cost recognized for stock options for the year ended December 31, 2015 was $1.4 million (2014 – $1.2 million), which is included in "Operating, maintenance and general" on the Consolidated Statements of Income.

As at December 31, 2015, cash received from option exercises was $2.1 million (2014 – $5.7 million). The total intrinsic value of options exercised for the year ended December 31, 2015 was $1.3 million (2014 – $4.2 million). The range of exercise prices for the options outstanding as at December 31, 2015 was $19.88 to $42.71 (2014 – $19.88 to $34.80).

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 Plans

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, subject to requirements to receive a minimum portion of their annual retainer in DSUs. 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, referred to as the Dividend Reinvestment Plan ("DRIP"), 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. Following retirement or resignation from the board, 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 during the ten trading days ending on the tenth trading day prior to the payment date.

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 DSUs for the year ended December 31, 2015 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, 2014	511,167	$ 24.38	301,086	$ 29.62
Granted including DRIP	98,442	36.17	61,664	35.14
Exercised	(2,963)	29.12	-	-
Outstanding and exercisable as at December 31, 2015	**606,646**	**$ 26.27**	**362,750**	**$ 31.36**

Compensation cost recognized for employee and director DSU for the year ended December 31, 2015 was $8.1 million (2014 – $9.1 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2015 were $2.7 million (2014 – $3.1 million); $0.5 million was offset with regulatory assets and regulatory liabilities (2014 – $0.6 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 PSUs for the year ended December 31, 2015 is presented in the following table:

	Employee PSU	Weighted Average Grant Date Fair Value	Aggregate intrinsic value
Outstanding as at December 31, 2014	457,582	$ 32.38	$ 17.7
Granted including DRIP	247,937	36.79	
Exercised	(204,583)	32.54	
Forfeited	(3,440)	33.63	
Outstanding as at December 31, 2015	**497,496**	**$ 34.50**	**$ 21.5**

Compensation cost recognized for the PSU plan for the year ended December 31, 2015 was $9.6 million (2014 – $8.9 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2015 were $3.1 million (2014 – $2.8 million).

37. 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 of the entity that could potentially be significant to the entity. In circumstances where Emera is not deemed the primary beneficiary, the VIE is accounted for using the equity method.

For the years ended, December 31, 2015 and 2014, the Company has identified the following significant VIEs:

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera was not the primary beneficiary since it does not have the controlling financial interest of NSPML. In Q2 2014, when the critical milestones were achieved and Nalcor Energy was deemed the beneficiary of the asset for financial reporting purposes as they have authority over the majority of the direct activities that are expected to most significantly impact the economic performance of the Maritime Link Project. Thus, Emera began recording the Maritime Link Project as an equity investment.

ECI has established a Self-Insurance Fund ("SIF") primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. ECI holds a variable interest in the SIF for which it was determined that ECI was the primary beneficiary and, accordingly, the SIF must be consolidated by ECI. In its determination that ECI controls the SIF, management considered that, in substance, the activities of the SIF are being conducted on behalf of ECI's subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF's operations. Additionally, because ECI, 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 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.

As at December 31, 2015, NSPI did not provide a guarantee to RESL (December 31, 2014 – $18.4 million). Until Q4 2015, NSPI held a variable interest in RESL, a VIE for which it was determined that NSPI was not the primary beneficiary since it did not have the controlling financial interest of RESL and did not have the power to direct the operations of the facility.

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

As at	**December 31, 2015**		December 31, 2014	
millions of Canadian dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Consolidated VIE				
BLPC SIF	**$ 101.4**	**$ 101.4**	$ 85.0	$ 85.0
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**187.6**	**1,007.0**	159.3	1,292.1
RESL	**-**	**-**	-	18.4

38. COMPARATIVE INFORMATION

These financial statements contain certain reclassifications of prior period amounts to be consistent with the current period presentation, with no effect on net income.

39. SUBSEQUENT EVENTS

On January 25, 2016, Emera announced an indirect wholly-owned subsidiary, Emera (Barbados) Holdings No. 2 Inc., ("EBH2"), will proceed to acquire the remaining ECI common shares from minority shareholders. Minority ECI shareholders can elect to receive $33.30 Barbadian dollar ("BBD") in cash per common share ("Cash Offer") or 2.1 Depositary Receipts ("DR") representing common shares of Emera ("DR Offer") or a combination of the two Offers by way of an amalgamation between ECI and a wholly-owned subsidiary of EBH2. Each Emera DR initially represented one quarter of an Emera common share.

ECI is also proposing to amend the terms of its 5.5 per cent cumulative preferred shares to make them redeemable at a 20 per cent premium to their issuance price. An ECI shareholders' meeting to vote on the amalgamation and preferred share amendment will take place on February 24, 2016.

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 12, 2016, the date the financial statements were issued.