EMERA INCORPORATED

Consolidated
Financial Statements

December 31, 2017 and 2016

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 considers 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 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 9, 2018

“Christopher Huskilson”
President and Chief Executive Officer

“Gregory Blunden”
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, 2017 and 2016, 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, 2017 and 2016, 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 9, 2018

"Ernst & Young LLP"
Chartered Professional Accountants
Licensed Public Accountants

Emera Incorporated
Consolidated Statements of Income

For the millions of Canadian dollars (except per share amounts)	Year ended December 31 **2017**	2016
Operating revenues		
Regulated electric	**$ 4,721**	$ 3,437
Regulated gas	**1,002**	499
Non-regulated	**503**	341
Total operating revenues	**6,226**	4,277
Operating expenses		
Regulated fuel for generation and purchased power	**1,638**	1,283
Regulated cost of natural gas	**379**	177
Non-regulated fuel for generation and purchased power	**209**	313
Non-regulated direct costs	**28**	29
Operating, maintenance and general	**1,399**	1,137
Provincial, state, and municipal taxes	**326**	195
Depreciation and amortization	**856**	588
Total operating expenses	**4,835**	3,722
Income from operations	**1,391**	555
Income from equity investments (note 6)	**124**	100
Other income (expenses), net (note 7)	**2**	174
Interest expense, net (note 8)	**698**	585
Income before provision for income taxes	**819**	244
Income tax expense (recovery) (note 9)	**520**	(22)
Net income	**299**	266
Non-controlling interest in subsidiaries	**5**	11
Preferred stock dividends	**28**	28
Net income attributable to common shareholders	**$ 266**	$ 227
Weighted average shares of common stock outstanding (in millions)(note 11)		
Basic	**213**	171
Diluted	**214**	172
Earnings per common share (note 11)		
Basic	**$ 1.25**	$ 1.33
Diluted	**$ 1.24**	$ 1.32
Dividends per common share declared	**$ 2.1325**	$ 1.9950

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 **2017**	 2016
Net income	**$ 299**	$ 266
Other comprehensive income (loss), net of tax		
Foreign currency translation adjustment (1)	**(462)**	32
Unrealized gains (losses) on net investment hedges (2) (3)	**97**	(49)
Cash flow hedges		
Net derivative gains (losses)	**10**	11
Less: reclassification adjustment for losses (gains) included in income (4)	**8**	11
Net effects of cash flow hedges	**18**	22
Unrealized gains on available-for-sale investment		
Unrealized gain (loss) arising during the period	**5**	3
Less: reclassification adjustment for (gains) recognized in income	**(1)**	(4)
Net unrealized holding gains (losses)	**4**	(1)
Net change in unrecognized pension and post-retirement benefit obligation (5)	**44**	12
Other equity method reclassification adjustment (6)	**-**	(46)
Other comprehensive income (loss) (7)	**(299)**	(30)
Comprehensive income (loss)	**-**	236
Comprehensive income (loss) attributable to non-controlling interest	**-**	8
Comprehensive Income of Emera Incorporated	**$ -**	$ 228

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

1) Net of tax recovery of nil (2016 - $3 million tax recovery) for the year ended December 31, 2017.
2) The Company has designated $1.2 billion United States dollar denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations.
3) Net of tax expense of $9 million (2016 - nil) for the year ended December 31, 2017.
4) Net of tax recovery of $1 million (2016 - nil) for the year ended December 31, 2017.
5) Net of tax recovery of $1 million (2016 - $3 million tax expense) for the year ended December 31, 2017.
6) Net of tax recovery of nil (2016 - $9 million tax recovery) for the year ended December 31, 2017.
7) Net of tax expense of $7 million (2016 - $9 million tax recovery) for the year ended December 31, 2017.

Emera Incorporated
Consolidated Balance Sheets

As at millions of Canadian dollars		**December 31 2017**		December 31 2016
Assets				
Current assets				
Cash and cash equivalents	**$**	**438**	$	404
Restricted cash (note 1)		**65**		87
Inventory (note 13)		**418**		472
Derivative instruments (notes 14 and 15)		**141**		145
Regulatory assets (note 16)		**138**		80
Receivables and other current assets (note 18)		**1,326**		1,323
		2,526		2,511
Property, plant and equipment, net of accumulated depreciation and amortization of $7,824 and $7,787, respectively (note 19)		**16,995**		17,290
Other assets				
Deferred income taxes (note 9)		**138**		125
Derivative instruments (notes 14 and 15)		**112**		131
Regulatory assets (note 16)		**1,238**		1,242
Net investment in direct financing lease (note 21)		**481**		488
Investments subject to significant influence (note 6)		**1,215**		947
Goodwill (note 22)		**5,805**		6,213
Other long-term assets		**261**		274
		9,250		9,420
Total assets	**$**	**28,771**	$	29,221
Liabilities and Equity				
Current liabilities				
Short-term debt (note 23)	**$**	**1,241**	$	961
Current portion of long-term debt (note 25)		**741**		476
Accounts payable		**1,161**		1,242
Derivative instruments (notes 14 and 15)		**227**		325
Regulatory liabilities (note 16)		**226**		362
Other current liabilities (note 24)		**350**		358
		3,946		3,724
Long-term liabilities				
Long-term debt (note 25)		**13,140**		14,268
Deferred income taxes (note 9)		**1,011**		1,672
Derivative instruments (notes 14 and 15)		**83**		150
Regulatory liabilities (note 16)		**2,242**		1,277
Pension and post-retirement liabilities (note 20)		**559**		669
Other long-term liabilities (note 6 and 26)		**609**		645
		17,644		18,681
Equity				
Common stock (note 10)		**5,601**		4,738
Cumulative preferred stock (note 28)		**709**		709
Contributed surplus		**76**		75
Accumulated other comprehensive income (loss) (note 12)		**(188)**		106
Retained earnings		**891**		1,076
Total Emera Incorporated equity		**7,089**		6,704
Non-controlling interest in subsidiaries (note 29)		**92**		112
Total equity		**7,181**		6,816
Total liabilities and equity	**$**	**28,771**	$	29,221

Commitments and contingencies (note 27)

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

Approved on behalf of the Board of Directors

"M. Jacqueline Sheppard" — **Chair of the Board**

"Christopher G. Huskilson" — **President and Chief Executive Officer**

Emera Incorporated
Consolidated Statements of Cash Flows

For the millions of Canadian dollars	Year ended December 31 **2017**	 2016
Operating activities		
Net income	**$ 299**	$ 266
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**851**	593
Income from equity investments, net of dividends	**(90)**	(59)
Allowance for equity funds used during construction	**(9)**	(22)
Deferred income taxes, net (1)	**469**	(67)
Net change in pension and post-retirement liabilities	**(12)**	13
Regulated fuel adjustment mechanism and fixed cost deferrals	**68**	63
Net change in fair value of derivative instruments	**(157)**	258
Net change in regulatory assets and liabilities (2)	**(237)**	(25)
Net change in capitalized transportation capacity	**84**	33
Foreign exchange (gain) loss	**(1)**	43
Gain on APUC sale of common shares and conversion of subscription receipts (note 7)	**-**	(223)
Other operating activities, net	**32**	46
Changes in non-cash working capital (note 30)	**(104)**	134
Net cash provided by operating activities	**1,193**	1,053
Investing activities		
Acquisition, net of cash acquired (note 4)	**-**	(8,409)
Additions to property, plant and equipment	**(1,529)**	(1,080)
Net purchase of investments subject to significant influence	**(213)**	(276)
Net proceeds on sale of investment (note 6)	**-**	665
Other investing activities	**(19)**	63
Net cash used in investing activities	**(1,761)**	(9,037)
Financing activities		
Change in short-term debt, net	**(31)**	118
Proceeds from short-term debt with maturities greater than 90 days	**383**	-
Proceeds from long-term debt, net of issuance costs	**129**	6,423
Proceeds from convertible debentures, net of issuance costs (note 10)	**-**	1,413
Retirement of long-term debt	**(453)**	(273)
Net borrowings (repayments) under committed credit facilities	**230**	(315)
Issuance of common stock, net of issuance costs	**682**	354
Dividends on common stock	**(287)**	(221)
Dividends on preferred stock	**(28)**	(28)
Dividends paid by subsidiaries to non-controlling interest	**(6)**	(5)
Other financing activities	**(26)**	(18)
Net cash provided by financing activities	**593**	7,448
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**(13)**	(65)
Net increase (decrease) in cash, cash equivalents, and restricted cash	**12**	(601)
Cash, cash equivalents, and restricted cash, beginning of year	**491**	1,092
Cash, cash equivalents and restricted cash, end of year	**503**	491
Cash, cash equivalents, and restricted cash consists of:		
Cash	**216**	221
Short-term investments	**222**	183
Restricted cash	**65**	87
Cash, cash equivalents, and restricted cash	**503**	491

Supplementary Information to Consolidated Statements of Cash Flows (note 30)

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

(1) 2017 includes the estimated $317 million revaluation of US non-regulated net deferred income tax assets as a result of tax reform.

(2) 2017 includes the net impact of the change in deferred taxes as a result of tax reform with an offset to a regulatory liability of $1.1 billion.

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	Non-Controlling Interest	Total Equity
Balance, December 31, 2016	$ 4,738	$ 709	$ 75	$ 106	$ 1,076	$ 112	$ 6,816
Net income of Emera Incorporated	-	-	-	-	294	5	299
Other comprehensive income (loss), net of tax expense of $7 million	-	-	-	(294)	-	(5)	(299)
Issuance of common stock, net of after-tax issuance costs	686	-	-	-	-	-	686
Dividends declared on preferred stock (note 28)	-	-	-	-	(28)	-	(28)
Dividends declared on common stock ($2.1325/share)	-	-	-	-	(451)	-	(451)
Common stock issued under purchase plan	173	-	-	-	-	-	173
Stock-based compensation	3	-	1	-	-	-	4
Repurchase of preferred shares of GBPC (note 29)	-	-	-	-	-	(14)	(14)
Other	1	-	-	-	-	(6)	(5)
Balance, December 31, 2017	$ 5,601	$ 709	$ 76	$ (188)	$ 891	$ 92	$ 7,181
Balance, December 31, 2015	$ 2,157	$ 709	$ 29	$ 137	$ 1,168	$ 134	$ 4,334
Net income of Emera Incorporated	-	-	-	-	255	11	266
Other comprehensive income (loss), net of tax recovery of $9 million	-	-	-	(27)	-	(3)	(30)
Issuance of common stock, net of after-tax issuance costs	2,450	-	-	-	-	-	2,450
Dividends declared on preferred stock (note 28)	-	-	-	-	(28)	-	(28)
Dividends declared on common stock ($1.9950/share)	-	-	-	-	(324)	-	(324)
Common stock issued under purchase plan	110	-	-	-	-	-	110
Stock-based compensation	18	-	1	-	-	-	19
Beneficial conversion feature, net of tax (note 8)	-	-	43	-	-	-	43
Acquisition of non-controlling interest of ECI	3	-	7	-	-	(25)	(15)
Other	-	-	(5)	(4)	5	(5)	(9)
Balance, December 31, 2016	$ 4,738	$ 709	$ 75	$ 106	$ 1,076	$ 112	$ 6,816

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

Emera Incorporated
Notes to the Consolidated Financial Statements
As at December 31, 2017 and 2016

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

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

Emera's primary rate-regulated subsidiaries and investments at December 31, 2017 included the following:

- Emera Florida and New Mexico represents TECO Energy, Inc. ("TECO Energy"), a holding company with regulated electric and gas utilities in Florida and New Mexico which was acquired on July 1, 2016. TECO Energy's holdings include:
    - Tampa Electric Company ("TEC"), which holds the Tampa Electric Division ("Tampa Electric"), an integrated regulated electric utility, serving approximately 750,000 customers in West Central Florida and Peoples Gas System Division, ("PGS") a regulated gas distribution utility, serving approximately 375,000 customers across Florida;
    - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 525,000 customers across New Mexico; and
    - TECO Finance, Inc. ("TECO Finance"), a wholly owned financing subsidiary of TECO Energy.
- Nova Scotia Power Inc. ("NSPI"), a fully integrated electric utility and the primary electricity supplier in Nova Scotia, serving approximately 515,000 customers;
- Emera Maine, an electric transmission and distribution utility, serving approximately 158,000 customers in Maine;
- Emera Caribbean represents Emera (Caribbean) Incorporated ("ECI"), a holding company that includes:
    - The Barbados Light & Power Company Limited ("BLPC"), a vertically integrated utility and sole provider of electricity on the island of Barbados, serving approximately 129,000 customers;
    - a 50.0 per cent direct and 30.4 per cent indirect interest (through a 60.7 per cent interest in ICD Utilities Limited) in Grand Bahama Power Company Limited ("GBPC"), a vertically integrated utility and sole provider of electricity on Grand Bahama Island, serving approximately 19,000 customers. On November 8, 2017, the minority shareholders of ICDU approved Emera's acquisition of their common shares for total consideration of approximately $35 million USD. The acquisition of the minority shareholder common shares was completed on January 15, 2018, increasing Emera's indirect ownership interest in GBPC to 100 per cent;
    - a 51.9 per cent interest in Dominica Electricity Services Ltd. ("Domlec"), an integrated utility on the island of Dominica, serving approximately 36,000 customers. On September 19, 2017 Dominica took a direct hit from Hurricane Maria, causing extensive damage across the island. Refer to note 16 for additional information; and
    - a 19.1 per cent indirect interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia.
- Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), 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, which expires in 2034;

- 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 generating first power in 2019 and full power in 2020. ENL's two investments are:
    - a 100 per cent investment in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.56 billion transmission project, including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. This project completed commissioning and entered service on January 15, 2018; and
    - a 49.5 per cent investment in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.7 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Nalcor Energy has indicated that the LIL will be in service in Q2 2018.
- a 12.9 per cent interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400-kilometre pipeline, which transports natural gas from offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States.

Emera also owns investments in other energy-related non-regulated companies, including:
- Emera Energy, consists of:
    - Emera Energy Services, 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" or "NEGG"), 1,115 MW of combined-cycle gas-fired electricity generating capacity in the northeastern United States;
    - Bayside Power Limited Partnership ("Bayside Power"), a 290 MW gas-fired combined cycle power plant in Saint John, New Brunswick;
    - Brooklyn Power Corporation ("Brooklyn Energy"), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia. Brooklyn Energy has a long-term purchase power agreement with NSPI; and
    - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 600 MW pumped storage hydroelectric facility in northwestern Massachusetts.
- Emera Reinsurance Limited, 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 US Finance LP, a wholly owned financing subsidiary of Emera;
- Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the United States;
- Emera Utility Services Inc., a utility services contractor primarily operating in Atlantic Canada; and
- other investments.

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.

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

Principles of Consolidation

The consolidated financial statements of Emera include the accounts of Emera Incorporated, its majority-owned subsidiaries, and a variable interest entity ("VIE") in which Emera is the primary beneficiary. Emera uses the equity method of accounting to record investments in which the Company has the ability to exercise significant influence, and for variable interest entities in which Emera is not the primary beneficiary. The consolidated financial statements include TECO Energy from the July 1, 2016 acquisition date through December 31, 2017.

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.

Intercompany balances and intercompany transactions have been eliminated on consolidation, except for the net profit on certain transactions between certain 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. An offset is recorded to property, plant and equipment, regulatory assets, regulated fuel for generation and purchased power, or operating, maintenance and general, depending on the nature of the transaction.

Use of Management Estimates

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect the reported amounts of assets and liabilities at the date of the financial statements, and 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. Actual results may differ significantly from these estimates.

Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third-party regulator. The rates are designed to recover the costs of providing the regulated products or services and provide a reasonable rate of return on the equity invested or assets as applicable (refer to note 16 for additional details).

Foreign Currency Translation

Monetary assets and liabilities, denominated in foreign currencies, are converted to Canadian dollars at the 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 foreign operations whose functional currency is not the Canadian dollar are translated using the exchange rates in effect at the balance sheet date and the results of operations at the average exchange rate in effect for the period. The resulting exchange gains and losses on the assets and liabilities are deferred on the balance sheet in AOCI.

The Company designates certain United States dollar denominated debt held in Canadian functional currency companies as hedges of net investments in United States dollar denominated foreign operations. The change in the carrying amount of these investments, measured at the exchange rates in effect at the balance sheet date, and the effective portion of the hedge, is recorded in Other Comprehensive Income ("OCI"). Any ineffectiveness is reflected in current period earnings.

Revenue Recognition

Operating revenues are recognized when electricity or gas 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 or gas is recognized at rates approved by the respective regulator and recorded based on meter readings and estimates, which occur on a systematic basis. At the end of each month, the electricity or gas 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.

Revenues for energy marketing and trading operations are presented on a net basis, reflecting the nature of the contractual relationships with customers and suppliers.

The Company records the net investment in a lease under the direct finance method for Emera Brunswick Pipeline, 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 and is recorded as "Operating revenues – regulated gas" on the Consolidated Statements of Income.

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

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.

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, asset retirement obligations ("ARO") 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 a future economic benefit.

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.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each functional class of depreciable property. For some of Emera's rate regulated subsidiaries depreciation is calculated using the group remaining life method which is applied to the average investment, adjusted for anticipated costs of removal less salvage, in functional classes of depreciable property. The service lives of regulated assets require the appropriate regulatory approval.

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. For some of Emera's rate regulated subsidiaries amortization is calculated using the amortizable life method which is applied to the net book value to date over the remaining life of those assets not classified as depreciable property above. The service lives of regulated intangible assets require the appropriate regulatory approval.

Goodwill

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated fair values of assets acquired and liabilities assumed at the acquisition date. Goodwill is carried at initial cost less any write-down for impairment. Under the applicable accounting guidance, goodwill is subject to an annual assessment for impairment at the reporting unit level. Refer to note 22 for further detail.

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. Management reviews all readily available current and historical information, including forward-looking information, and the likelihood that deferred tax assets will be recovered from future taxable income is assessed and assumptions about the expected timing of the reversal of deferred tax assets and liabilities are made. 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 TECO Energy and Emera Maine on regulated assets are deferred and amortized over the estimated service lives of the related properties, as required by state 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 by a regulator to flow deferred income taxes through earnings. These regulated assets or liabilities are grossed up using the respective income tax rate to reflect the income tax associated with future revenues that are 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.

Emera classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively. Refer to note 9 for further details.

Derivatives and Hedging Activities

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 any changes in fair value are recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

Derivatives entered into by Tampa Electric, PGS, NMGC, 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. 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, with changes in fair value 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 marketing and trading 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.

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 and other current assets” and obligations to return cash collateral are recognized in “Accounts payable”.

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist of highly liquid short-term investments with original maturities of three months or less at acquisition. Total short-term investments of $222 million have an effective interest rate of 1.4 per cent at December 31, 2017 (2016 – $183 million with an effective interest rate of 0.6 per cent).

Amounts included in restricted cash represent funds required to be set aside for the BLPC Self-Insurance Fund (notes 6 and 32).

Receivables and Allowance for Doubtful Accounts

Customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity and gas 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, customer deposits, 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.

Inventory

Fuel and materials inventories are valued using the weighted-average cost method. These inventories are carried at the lower of weighted-average cost or net realizable value, unless evidence indicates that the weighted-average cost will be recovered in future customer rates.

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.

Asset Impairment

Goodwill

Goodwill is not amortized, but is subject to an annual assessment for impairment at the reporting unit level. Reporting units are generally determined at the operating segment level or one level below the operating segment level. Reporting units with similar characteristics are grouped for the purpose of determining impairment, if any, of goodwill. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. If an entity performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount or if an entity chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Emera reviews recorded goodwill at least annually (during the fourth quarter) for each reporting unit, with interim impairment tests performed when impairment indicators are present. Refer to note 22 for further detail.

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 in the Consolidated Statements of Income.

Asset Retirement Obligations

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

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

Cost of Removal

Tampa Electric, PGS, NMGC and NSPI recognize non-ARO costs of removal as regulatory liabilities. The non-ARO costs of removal represent estimated funds received from customers through depreciation rates to cover future non-legally required cost of removal of property, plant and equipment upon retirement. The companies accrue for removal costs over the life of the related assets based on depreciation studies approved by their respective regulators. The costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays.

Franchise Fees and Gross Receipts

Tampa Electric and PGS are allowed to recover from customers certain costs incurred, on a dollar-for-dollar basis, through prices approved by the Florida Public Service Commission ("FPSC"). The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues in the Consolidated Statements of Income. Franchise fees and gross receipt taxes payable by Tampa Electric and PGS are included as an expense on the Consolidated Statements of Income in "Provincial, state and municipal taxes".

NMGC is an agent in the collection and payment of franchise fees and gross receipt taxes and is not required by a tariff to present the amounts on a gross basis. Therefore, NMGC's franchise fees and gross receipt taxes are presented net with no line item impact on the Consolidated Statement of Income.

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.

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 or regulatory assets.

2. CHANGE IN ACCOUNTING POLICY

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2017, are described as follows:

Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows
In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows*. The standard provides guidance regarding the classification of certain cash receipts and cash payments on the statement of cash flows, where specific guidance is provided for issues not previously addressed. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. The Company has early adopted the standard with no impact on the consolidated financial statements as a result of implementation of this standard.

Restricted Cash on the Statement of Cash Flows

In November 2016, the FASB issued ASU 2016-18, *Restricted Cash on the Statement of Cash Flows*. The standard requires the Company to show the changes in total cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. Transfers between cash and cash equivalents and restricted cash and restricted cash equivalents are no longer presented in the statement of cash flows. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. The Company has early adopted this standard. This change in accounting policy has increased net cash used in investing activities by $22 million for the year ended December 31, 2017 (2016 – a decrease of $68 million) within the Consolidated Statement of Cash Flows. Changes in restricted cash are now disclosed within the Consolidated Statement of Cash Flows for all years presented. Restricted cash was $65 million at December 31, 2017 (2016 – $87 million).

Simplifying the Test for Goodwill Impairment

In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment*. The standard provides guidance to simplify the subsequent measurement of goodwill by eliminating the second step of the quantitative test. The new guidance does not amend the optional qualitative assessment of goodwill impairment. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019, with early adoption permitted and is required to be applied prospectively. The Company has early adopted the standard with no impact on the consolidated financial statements as a result of implementation of this standard.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs issued by FASB. The following updates have been issued by FASB, but have not yet been adopted by Emera. Any ASUs not included below were assessed and determined to be either not applicable to the Company or have insignificant impact on the consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, which creates a new, principle-based revenue recognition framework, codified as Accounting Standards Codification ("ASC") Topic 606. The FASB issued amendments to ASC Topic 606 during 2016 to clarify certain implementation guidance and to reflect scope improvements and practical expedients. The guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and will allow for either full retrospective adoption or modified retrospective adoption. The Company will adopt this guidance effective January 1, 2018, using the modified retrospective approach.

The Company implemented a revenue recognition project plan in 2016. In Q1 2017, the Company concluded that the accounting for contributions in aid of construction will be out of the scope of the new standard. In Q2 2017, the Company completed an analysis of material regulated revenue streams and collectability risk and concluded that there will be no material changes on adoption of this standard. In Q3 2017, the Company completed an analysis of material unregulated revenue streams and concluded that there will be no material changes on adoption of this standard. The Company also evaluated the disclosure requirements and determined that the disaggregation of revenue information required by the new standard will not have a significant impact on the Company's information gathering processes and procedures as the revenue information required by the standard is consistent with historical revenue information gathered by the Company for financial reporting purposes. The Company continues to monitor the assessment of ASC Topic 606 by the AICPA Power and Utilities Revenue Recognition Task Force for developments.

Recognition and Measurement of Financial Assets and Financial Liabilities
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. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The standard requires investments in equity securities, except those accounted for under the equity method of accounting or those that result in consolidation, to be measured at fair value. The Company will elect to measure equity securities that do not have a readily determinable fair value, at cost minus impairment (if any), plus or minus observable price changes resulting from transactions for the identical or a similar investment of the same issuer. The standard eliminates the available-for-sale classification for equity investments that recognized changes in the fair value as a component of other comprehensive income, resulting in all changes in fair value being recognized in net income. The increase in volatility of Other income (expense), net as a result of the remeasurement of equity investments is not expected to be significant. The Company will adopt this guidance effective January 1, 2018 with a cumulative-effect adjustment of approximately $3 million to retained earnings in the Consolidated Balance Sheet.

Leases
In February 2016, the FASB issued ASU 2016-02, *Leases*. The standard, codified as ASC Topic 842, increases transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with terms of more than 12 months. Under the existing guidance, operating leases are not recorded as assets and liabilities on the balance sheet. The effect of leases on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. The guidance will require additional disclosures regarding key information about leasing arrangements. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted, and is required to be applied using a modified retrospective approach.

In January 2018, the FASB issued an amendment to ASC Topic 842 which permits companies to elect an optional transition practical expedient to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. In November 2017, the FASB voted to amend ASC Topic 842 to allow companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The amendment is expected to be finalized in Q1 2018.

The Company is in the process of evaluating the impact of adoption of this standard on its financial statements and disclosures. In Q3 2017, the Company implemented a project plan. In Q4 2017, the Company began execution of the project plan, including training sessions with key stakeholders throughout the organization and gathering detailed information on existing lease arrangements. This includes evaluating the available practical expedients, calculating the lease asset and liability balances associated with individual contractual arrangements and assessing the disclosure requirements. The Company continues to monitor FASB amendments to ASC Topic 842.

Measurement of Credit Losses on Financial Instruments
In June 2016, the FASB issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*. The standard provides guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted for annual reporting periods, including interim periods after December 15, 2018 and will be applied using a modified retrospective approach. The Company is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Clarifying the Definition of a Business
In January 2017, the FASB issued ASU 2017-01, *Clarifying the Definition of a Business*. The standard provides guidance to assist entities with evaluating when a set of transferred assets and activities is a business. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted and is required to be applied prospectively. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost
In March 2017, the FASB issued ASU 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The guidance requires the service cost component of defined benefit pension or other postretirement benefit plans to be reported in the same line items as other compensation costs. The other components of net benefit cost are required to be presented in the Consolidated Statements of Income outside of income from operations. Only the service cost component will be eligible for capitalization as property, plant and equipment under this guidance. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The guidance is required to be applied retrospectively for presentation in the Consolidated Statements of Income and prospectively for the guidance limiting capitalization. In Q4, 2017 the Company completed an analysis of the impact of the adoption of this standard on the consolidated financial statements and concluded that the impact on the balance sheet will be minimal. The other components of net benefit cost that will be required to be presented outside of income from operations in the Consolidated Statements of Income on adoption are $28 million for the year ended December 31, 2017. The Company will adopt this guidance effective January 1, 2018.

Targeted Improvements to Accounting for Hedging Activities
In August 2017, the FASB issued ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities,* which amends the hedge accounting recognition and presentation requirements in ASC Topic 815. This standard improves the transparency and understandability of information about an entity's risk management activities by better aligning the entity's financial reporting for hedging relationships with those risk management activities and simplifies the application of hedge accounting. The standard will make more financial and nonfinancial hedging strategies eligible for hedge accounting, amends the presentation and disclosure requirements for hedging activities and changes how entities assess hedge effectiveness. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018, with early adoption permitted, and is required to be applied using a modified retrospective approach. The Company is currently evaluating the impact of the adoption of this standard on the consolidated financial statements.

4. ACQUISITION

TECO ENERGY INC.

On July 1, 2016, Emera acquired all of the outstanding common shares of TECO Energy for $27.55 US dollars ("USD") per common share. The net cash purchase price totalled $8.4 billion ($6.5 billion USD), with an aggregate purchase price of $13.9 billion ($10.7 billion USD), including the assumption of $5.5 billion ($4.2 billion USD) in US debt on closing.

The majority of TECO Energy's operations are subject to the rate-setting authority of the Federal Energy Regulatory Commission ("FERC"), FPSC, and New Mexico Public Regulation Commission ("NMPRC"), and are accounted for pursuant to USGAAP, including the accounting guidance for regulated operations. Except for unregulated long-term debt acquired and deferred taxes, fair values of tangible and intangible assets and liabilities subject to these rate-setting provisions approximate their carrying values due to the fact that a market participant would not expect to recover any more or less than their net carrying value. Accordingly, assets acquired and liabilities assumed and pro-forma financial information do not reflect any adjustments related to these amounts.

The acquisition is accounted for in accordance with the acquisition method of accounting. The excess of purchase price over estimated fair values of assets acquired and liabilities assumed has been recognized as goodwill at the acquisition date of July 1, 2016. The goodwill reflects the value paid for access to regulated assets, net income and cash flows in growth markets, opportunities for adjacency growth, long-term potential for enhanced access to capital as a result of increased scale and business diversity, and an improved earnings risk profile. The goodwill recognized as part of this transaction is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to this goodwill.

The following table summarizes the final allocation of the purchase consideration to the assets and liabilities acquired as at July 1, 2016 based on their fair values, using the July 1, 2016 exchange rate of $1.00 USD = $1.3009 CAD.

		millions of Canadian dollars
Purchase Consideration	$	8,447
Fair value assigned to net assets:		
Current assets (1)	$	619
Regulatory assets (including current portion)		624
Property, plant and equipment, net		10,023
Other long-term assets		71
Current liabilities		(747)
Assumed long-term debt (including current portion)		(5,409)
Regulatory liabilities (including current portion)		(1,117)
Deferred income taxes		(800)
Pension and post-retirement liabilities (including current portion)		(480)
Other long-term liabilities		(146)
	$	2,638
Cash and cash equivalents		38
Fair value of net assets acquired	$	2,676
Goodwill	$	**5,771**

(1) Includes accounts receivables with fair value of $334 million comprised of gross contract value of $337 million, and $3 million of contractual receivables not expected to be collected.

Goodwill has been allocated to the TECO Energy reporting units as follows:

millions of Canadian dollars Reporting Unit		Goodwill
Tampa Electric	$	**4,552**
PGS		**744**
New Mexico Gas		**475**
Goodwill	**$**	**5,771**

Goodwill is subject to an annual assessment for impairment at the reporting unit level. Adverse changes in assumptions could result in a material impairment of Emera's goodwill (refer to note 22).

Acquisition Related Expenses

There were no acquisition related expenses incurred for the year ended December 31, 2017. Acquisition related expenses totalled $250 million ($166 million after tax) for the year ended December 31, 2016. These acquisition related expenses were included in Interest expense, net and Operating, maintenance and general on the Consolidated Statements of Income.

Supplemental Pro Forma Data

The unaudited pro forma financial information below gives effect to the acquisition of TECO Energy as if the transaction had occurred at the beginning of 2016. This pro forma data is presented for information purposes only, and does not purport to be indicative of the results that would have occurred had the acquisition taken place at the beginning of 2016, nor is it indicative of the results that may be expected in future periods.

Pro forma net income attributable to common shareholders excludes all non-recurring acquisition-related expenses incurred by TECO Energy and Emera and includes adjustments for pro forma financing costs associated with the acquisition. Total after-tax adjustments increased pro forma net income attributable to common shareholders by $53 million for the year ended December 31, 2016.

For the millions of Canadian dollars		Year ended December 31, 2016
Pro forma operating revenues	**$**	6,034
Pro forma net income attributable to common shareholders	**$**	386

5. SEGMENT INFORMATION

Emera manages its reportable segments separately due in part 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 reported to the Company's chief operating decision maker. Emera's six reportable segments are Emera Florida and New Mexico, NSPI, Emera Maine, Emera Caribbean, Emera Energy and Corporate and Other (includes Emera Utility Services, ENL, Emera Brunswick Pipeline, Corporate, other strategic investments and holding companies).

millions of Canadian dollars	Emera Florida and New Mexico	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-segment Eliminations	Total
For the year ended December 31, 2017								
Operating revenues from external customers (1)	$ **3,623**	$ **1,335**	$ **297**	$ **434**	$ **451**	$ **86**	$ **-**	$ **6,226**
Inter-segment revenues (1)	**-**	**3**	**-**	**-**	**14**	**41**	**(58)**	**-**
Total operating revenues	**3,623**	**1,338**	**297**	**434**	**465**	**127**	**(58)**	**6,226**
Allowance for funds used during construction - debt and equity	**5**	**8**	**3**	**-**	**-**	**-**	**-**	**16**
Regulated fuel and fixed cost deferral adjustments	**-**	**59**	**-**	**-**	**-**	**-**	**-**	**59**
Depreciation and amortization	**500**	**207**	**47**	**51**	**48**	**3**	**-**	**856**
Interest expense (2)	**248**	**134**	**20**	**25**	**2**	**276**	**-**	**705**
Internally allocated interest (3)	**-**	**-**	**-**	**-**	**(24)**	**24**	**-**	**-**
Income from equity investments	**-**	**-**	**1**	**3**	**24**	**96**	**-**	**124**
Income tax expense (recovery)	**529**	**-**	**27**	**-**	**18**	**(54)**	**-**	**520**
Net income attributable to common shareholders	**99**	**129**	**46**	**31**	**93**	**(132)**	**-**	**266**
Capital expenditures	**910**	**385**	**82**	**72**	**47**	**26**	**-**	**1,522**
As at December 31, 2017								
Total assets	**17,216**	**4,979**	**1,505**	**1,251**	**1,575**	**2,331**	**(86)**	**28,771**
Investments subject to significant influence	**-**	**-**	**13**	**39**	**-**	**1,163**	**-**	**1,215**
Goodwill	**5,566**	**-**	**143**	**96**	**-**	**-**	**-**	**5,805**

(1) All significant intercompany balances and intercompany 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. Intercompany 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) Interest expense net of interest revenue. Corporate and Other Interest expense has also been reduced by amortization of $24 million related to the unregulated long-term debt fair market value adjustment recognized on the acquisition of TECO Energy.
(3) Segment net income is reported on a basis that includes internally allocated financing costs.

millions of Canadian dollars	Emera Florida and New Mexico (2)	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-segment Eliminations	Total
For the year ended December 31, 2016								
Operating revenues from external customers (1)	$ 1,839	$ 1,354	$ 297	$ 419	$ 298	$ 69	$ -	$ 4,276
Inter-segment revenues (1)	-	2	-	-	11	24	(36)	1
Total operating revenues	1,839	1,356	297	419	309	93	(36)	4,277
Allowance for funds used during construction - debt and equity	28	6	1	-	-	-	-	35
Regulated fuel and fixed cost deferral adjustments	-	61	-	-	-	-	-	61
Depreciation and amortization	243	197	51	48	45	4	-	588
Interest expense (3)	125	127	19	15	1	311	-	598
Internally allocated interest (4)	-	-	-	-	(24)	24	-	-
Income from equity investments	-	-	-	3	11	86	-	100
Income tax expense (recovery)	100	12	23	14	(53)	(118)	-	(22)
Net income attributable to common shareholders	172	130	47	100	(110)	(112)	-	227
Capital expenditures	547	304	85	87	39	7	-	1,069
As at December 31, 2016								
Total assets	18,016	4,776	1,543	1,331	1,702	1,966	(113)	29,221
Investments subject to significant influence	-	-	13	39	-	895	-	947
Goodwill	5,957	-	154	102	-	-	-	6,213

(1) All significant intercompany balances and intercompany 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. Intercompany 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) Financial results of Emera Florida and New Mexico are from July 1, 2016, the date of the acquisition.
(3) Interest expense net of interest revenue. Corporate and Other Interest expense has also been reduced by amortization of $13 million related to the unregulated long-term debt fair market value adjustment recognized on the acquisition of TECO Energy.
(4) 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 **2017**	2016
Canada	**$ 1,464**	$ 1,510
United States	**4,328**	2,348
Barbados	**280**	254
The Bahamas	**119**	121
Dominica	**35**	44
	$ 6,226	$ 4,277

(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 2017**	December 31 2016
Canada	**$ 3,995**	$ 3,791
United States	**12,257**	12,724
Barbados	**408**	416
The Bahamas	**276**	295
Dominica	**59**	64
	$ 16,995	$ 17,290

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
	2017	2016	**2017**	2016	**2017**
NSPML	**$ 510**	$ 315	**$ 36**	$ 21	**100.0**
LIL (1)	**492**	400	**37**	24	**49.5**
M&NP (2)	**156**	175	**23**	23	**12.9**
Lucelec (2)	**39**	39	**3**	3	**19.1**
Bear Swamp (3)	**-**	-	**23**	11	**50.0**
APUC (4)	**-**	-	**-**	18	**-**
Other Investments	**18**	18	**2**	-	
	$ 1,215	$ 947	**$ 124**	$ 100	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.9 per cent of the total units issued. Emera's percentage ownership in LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined upon completion of the LIL and final costing of all transmission projects related to the Muskrat Falls development, including the LIL, Labrador Transmission Assets 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.
(2) 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.
(3) The investment balance in Bear Swamp is in a credit position, primarily a result of a $179 million distribution received in Q4 2015. Bear Swamp's credit investment balance of $188 million (2016 - $217 million) is recorded in "Other long-term liabilities" on the Consolidated Balance Sheets.
(4) In two separate transactions in 2016, Emera sold a total of 63 million common shares in APUC. Emera no longer holds any interest in APUC.

Equity investments include a $13 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 32). NSPML's consolidated summarized balance sheets are illustrated as follows:

As at millions of Canadian dollars	December 31 2017	2016
Balance Sheets		
Current assets	**$ 225**	$ 439
Property, plant and equipment	**1,720**	1,132
Non-current assets	**74**	276
Total assets	**$ 2,019**	$ 1,847
Current liabilities	**$ 180**	$ 219
Long-term debt	**1,287**	1,288
Non-current liabilities	**42**	25
Equity	**510**	315
Total liabilities and equity	**$ 2,019**	$ 1,847

7. OTHER INCOME (EXPENSES), NET

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

For the millions of Canadian dollars	Year ended December 31 2017	2016
Gain on sale of APUC common shares (note 6)	**$ -**	$ 160
Gain on conversion of APUC subscription receipts and dividend equivalents to common shares of APUC (note 6)	**-**	63
Gain on BLPC Self-Insurance Fund ("SIF") regulatory liability (1)	**-**	53
Foreign exchange (losses) gains and mark-to-market adjustments related to the TECO Energy acquisition (2)	**-**	(135)
Other	**2**	33
	$ 2	$ 174

(1) In June 2016, BLPC secured support from the Government of Barbados and the Trustees of the SIF to reduce the contingency funding in the SIF to $22 million USD. As a result, Emera reduced the SIF regulatory liability to $30 million ($22 million USD) and recorded a pre-tax gain of $53 million (after-tax gain of $43 million).
(2) Mark-to-market adjustments included in Emera's other income related to the effect of TECO Energy convertible debenture related USD-denominated currency and forward contracts. These contracts were put in place to economically hedge the anticipated proceeds from the 2015 sale of $2.185 billion 4 per cent convertible unsecured subordinated debentures represented by instalment receipts ("the Debenture Offering" or "Debentures" or "Convertible Debentures") for the TECO Energy acquisition.

8. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of Canadian dollars	Year ended December 31 2017	2016
Interest on debt	**$ 663**	$ 443
Beneficial conversion feature (note 10)	**-**	62
Interest on Convertible Debentures (note 10)	**-**	65
Interest on acquisition credit facility related to the TECO Energy acquisition (note 4)	**-**	11
Allowance for borrowed funds used during construction	**(7)**	(13)
Other	**42**	17
	$ 698	$ 585

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		**2017**		2016
Income before provision for income taxes	**$**	**819**	$	244
Statutory income tax rate		**31%**		31%
Income taxes, at statutory income tax rate		**254**		76
Revaluation of US non-regulated deferred income taxes		**317**		-
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities		**(54)**		(47)
Foreign tax rate variance		**36**		(5)
Financing deductions		**(17)**		(17)
Tax effect of equity earnings		**(12)**		(10)
Manufacturing and investment allowances		**(8)**		(7)
Non-taxable portion of gains on APUC transactions		**-**		(34)
Non-deductible portion of foreign exchange and mark-to-market adjustments related to the TECO Energy acquisition		**-**		21
Other		**4**		1
Income tax expense (recovery)	**$**	**520**	$	(22)
Effective income tax rate		63%		(9)%

The statutory income tax rate of 31 per cent represents the combined Canadian federal and Nova Scotia and New Brunswick provincial corporate income tax rates, which are the relevant tax jurisdictions for Emera.

On December 22, 2017, the US Tax Cuts and Jobs Act of 2017 (“the Act”) was signed into legislation. The Act includes a broad range of legislative changes including a reduction of the US federal corporate income tax rate from 35 per cent to 21 per cent effective January 1, 2018, limitations on the deductibility of interest and 100 per cent expensing of qualified property. The Act provides an exemption to regulated electric and gas utilities from the limitations on the deductibility of interest and the 100 per cent expensing of qualified property.

As a result of the Act being enacted during 2017, the Company is required to revalue its United States deferred income tax assets and liabilities based on the new 21 per cent tax rate. The Company has recognized an estimated $317 million income tax expense in 2017 as a result of the revaluation of its US non-regulated net deferred income tax assets. The Company has also reduced its US regulated net deferred income tax liabilities by an estimated $1.1 billion and recorded an equivalent regulatory liability since the benefit of lower US taxes is expected to be returned to customers over time as required by the Act or by order of the applicable regulator.

As discussed above, the Company has provisionally revalued all of its US deferred tax assets and liabilities based on the rates they are expected to reverse at in the future, which is generally 21 per cent for US federal tax purposes. The December 31, 2017 balances of deferred tax assets and deferred tax liabilities that have been revalued are $1.3 billion and $1.8 billion, respectively. The Company is still analyzing certain aspects of the Act, which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts. Further adjustments, if any, will be recorded by the Company during the measurement period in 2018 as permitted by SEC Staff Accounting Bulletin 118, Income tax Accounting Implications of the Tax Cuts and Jobs Act.

The following reflects the composition of taxes on income from continuing operations presented in the Consolidated Statements of Income for the years ended December 31:

millions of Canadian dollars		**2017**		2016
Current income taxes				
Canada	**$**	**24**	$	13
United States		**24**		18
Other		**3**		15
Deferred income taxes				
Canada		**3**		(113)
United States		**384**		151
Other		**(1)**		-
Operating loss carry forwards				
Canada		**(40)**		(2)
United States		**(194)**		(104)
Revaluation of US non-regulated deferred income taxes				
United States		**317**		-
Income tax expense (recovery)	**$**	**520**	$	(22)

The following reflects the composition of income before provision for income taxes presented in the Consolidated Statements of Income for the years ended December 31:

millions of Canadian dollars		**2017**		2016
Canada	**$**	**88**	$	71
United States		**693**		44
Other		**38**		129
Income before provision for income taxes	**$**	**819**	$	244

The deferred income tax assets and liabilities presented in the Consolidated Balance Sheets as at December 31 consisted of the following:

millions of Canadian dollars		**2017**		2016
Deferred income tax assets:				
Tax loss carry forwards	**$**	**853**	$	1,036
Tax credit carry forwards		**314**		318
Regulatory liabilities - cost of removal		**208**		388
Pension and post-retirement liabilities		**124**		153
Derivative instruments		**107**		150
Other		**394**		490
Total deferred income tax assets before valuation allowance		**2,000**		2,535
Valuation allowance		**(105)**		(58)
Total deferred income tax assets after valuation allowance	**$**	**1,895**	$	2,477
Deferred income tax (liabilities):				
Property, plant and equipment	**$**	**(2,321)**	$	(3,553)
Derivative instruments		**(155)**		(202)
Other		**(292)**		(269)
Total deferred income tax liabilities	**$**	**(2,768)**	$	(4,024)
Consolidated Balance Sheets presentation:				
Long-term deferred income tax assets	**$**	**138**	$	125
Long-term deferred income tax liabilities		**(1,011)**		(1,672)
Net deferred income tax liabilities	**$**	**(873)**	$	(1,547)

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.

Emera's gross net operating loss ("NOL") carry forwards, capital loss carry forwards and tax credit carry forwards as at December 31, consisted of the following:

millions of Canadian dollars		**2017**		2016
Canada				
NOL	**$**	**532**	$	199
Capital loss		**77**		77
United States				
Federal NOL	**$**	**2,926**	$	2,595
State NOL		**1,271**		1,183
Capital loss		**13**		14
Tax credit		**314**		318
Other				
NOL	**$**	**29**	$	22

The following table summarizes as at December 31, 2017 the deferred tax assets associated with NOL, capital loss and tax credit carry forwards and the associated expiration 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
Canada							
NOL	$	164	$	(80)	$	84	2027-2037
Capital loss		16		(16)		-	Indefinite
United States							
Federal NOL	$	602	$	-	$	602	2024-2037
State NOL		65		(2)		63	2024-2037
Capital loss		2		(2)		-	2018-2019
Tax credit		314		-		314	2019-Indefinite
Other							
NOL	$	4	$	(4)	$	-	2018-2024

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 loss carry forwards noted above and unrealized capital losses on certain investments. A valuation allowance of $105 million has been recorded as at December 31, 2017 (2016 - $58 million) related to the loss carry forwards 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		**2017**		2016
Balance, January 1	**$**	**18**	$	6
Increases due to tax positions related to current year		**1**		12
Balance, December 31	**$**	**19**	$	18

The total amount of unrecognized tax benefits as at December 31, 2017 was $19 million (2016 - $18 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $1 million (2016 - $1 million). No penalties have been accrued. The balance of unrecognized tax benefits could change in the next twelve months as a result of resolving Canada Revenue Agency ("CRA") and Internal Revenue Service audits. A reasonable estimate of any change cannot be made at this time.

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 $822 million as at December 31, 2017 (2016 - $667 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 and New Brunswick provincial income tax. Emera's subsidiaries file Canadian, US, Barbados, St. Lucia and Dominica income tax returns. As at December 31, 2017, the Company's tax years still open to examination by taxing authorities include 2005 and subsequent years.

NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for NSPI's 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 million, including interest. NSPI has prepaid $23 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. 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. Should NSPI receive similar notices of reassessment for years not currently in dispute, further payments will be required; however, the ultimate permissibility of these deductions would be similarly not in dispute.

NSPI and its advisors believe NSPI has reported its tax position appropriately and NSPI is disputing the reassessments through the CRA Appeal process. NSPI continues to assess its options to resolving the dispute however the outcome of the Appeal process is not determinable at this time.

10. COMMON STOCK

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

Issued and outstanding:		**2017**			2016	
	millions of shares		millions of Canadian dollars	millions of shares		millions of Canadian dollars
Balance, December 31, 2016	**210.02**	**$**	**4,738**	147.21	$	2,157
Conversion of Convertible Debentures (1)	**0.15**		**6**	51.99		2,115
Issuance of common stock (2)	**14.61**		**680**	7.69		338
Issued for cash under Purchase Plans at market rate	**3.89**		**182**	2.51		115
Discount on shares purchased under Dividend Reinvestment Plan	**-**		**(9)**	-		(5)
Options exercised under senior management share option plan	**0.10**		**3**	0.62		17
Employee share purchase plan	**-**		**1**	-		1
Balance, December 31 2017	**228.77**	**$**	**5,601**	210.02	$	4,738

(1) As at December 31, 2017, a total of 52.14 million common shares of the Company were issued, representing conversion into common shares of more than 99.9% of the Convertible Debentures.
(2) On December 28, 2017, Emera completed an offering of 14.6 million common shares, at $47.90 per common share, for gross proceeds of approximately $700 million. The net proceeds were $680 million after $20 million of issuance costs, net of taxes.

As at December 31, 2017, there were the following common shares reserved for issuance: 6.5 million (2016 – 6.6 million) under the senior management stock option plan, 1.3 million (2016 – 1.5 million) under the employee common share purchase plan and 4.2 million (2016 – 7.9 million) under the dividend reinvestment plan.

The issuance of common shares under the common share compensation arrangements does not allow the plans to exceed 10 per cent of Emera's outstanding common shares. As at December 31, 2017, Emera is in compliance with this requirement.

Convertible Debentures

In 2015, to finance a portion of the acquisition of TECO Energy, Emera completed the sale of $2.185 billion aggregate principal amount of 4 per cent convertible unsecured subordinated debentures, represented by instalment receipts. The Debentures were sold on an instalment basis at a price of $1,000 per Debenture, maturing on September 29, 2025. As of August 2, 2016, the Final Instalment Date, the Debentures bear interest at 0 per cent. At maturity, Emera has the right to pay the principal amount due in common shares to the debenture holders that have not converted, which will be valued at 95 per cent of the weighted average trading price on the TSX for the 20 consecutive trading days ending five trading days preceding the maturity date.

As at December 31, 2017, a total of 52.14 million common shares of the Company were issued, representing conversion into common shares of more than 99.9 per cent of the Convertible Debentures.

11. 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, convertible debentures and shares issued under the dividend reinvestment plan.

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 **2017**	 2016
Numerator		
Net income attributable to common shareholders	**$ 266.1**	$ 227.2
Convertible Debentures	**-**	0.2
Diluted numerator	**266.1**	227.4
Denominator		
Weighted average shares of common stock outstanding	**212.3**	170.4
Weighted average deferred share units outstanding	**1.1**	1.0
Weighted average shares of common stock outstanding – basic	**213.4**	171.4
Stock-based compensation	**0.6**	0.6
Convertible Debentures	**0.1**	0.2
Weighted average shares of common stock outstanding – diluted	**214.1**	172.2
Earnings per common share		
Basic	**$ 1.25**	$ 1.33
Diluted	**$ 1.24**	$ 1.32

12. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of accumulated other comprehensive income are as follows:

millions of Canadian dollars	Unrealized (loss) gain on translation of self-sustaining foreign operations	Net change in net investment hedges	(Losses) gains on derivatives recognized as cash flow hedges	Net change on available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the year ended December 31, 2017						
Balance, January 1, 2017	$ 486	$ (49)	$ (21)	$ (1)	$ (309)	$ 106
Other comprehensive income (loss) before reclassifications	(457)	97	10	5	-	(345)
Amounts reclassified from accumulated other comprehensive income loss	-	-	8	(1)	44	51
Net current period other comprehensive income (loss)	(457)	97	18	4	44	(294)
Other	-	-	-	-	-	-
Balance, December 31, 2017	$ 29	$ 48	$ (3)	$ 3	$ (265)	$ (188)

millions of Canadian dollars	Unrealized (loss) gain on translation of self-sustaining foreign operations	Net change in net investment hedges	(Losses) gains on derivatives recognized as cash flow hedges	Net change on available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the year ended December 31, 2016						
Balance, January 1, 2016	$ 490	$ -	$ (35)	$ -	$ (318)	$ 137
Other comprehensive income (loss) before reclassifications	35	(49)	11	3	-	-
Amounts reclassified from accumulated other comprehensive income loss (gain)	-	-	11	(4)	12	19
Equity method reclassification adjustments	(35)	-	(8)	-	(3)	(46)
Net current period other comprehensive income (loss)	-	(49)	14	(1)	9	(27)
Other	(4)	-	-	-	-	(4)
Balance, December 31, 2016	$ 486	$ (49)	$ (21)	$ (1)	$ (309)	$ 106

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

For the		Year ended December 31	
millions of Canadian dollars		**2017**	2016
	Affected line item in the Consolidated Financial Statements	Amounts reclassified from AOCI	
Equity method reclassification adjustments			
	Investments subject to significant influence	$ **-**	$ 54
Total before tax		**-**	54
	Deferred income taxes	**-**	(8)
Total net of tax		$ **-**	$ 46
Losses (gain) on derivatives recognized as cash flow hedges			
Power and gas swaps	Non-regulated fuel for generation and purchased power	$ **(3)**	$ (2)
Interest rate swaps	Income from equity investments	**-**	1
Foreign exchange forwards	Operating revenue - regulated	**10**	12
Total before tax		**7**	11
	Income tax recovery (expense)	**1**	-
Total net of tax		$ **8**	$ 11
Net change in available-for-sale investments			
	Other income (expenses), net	$ **(1)**	$ (4)
Total before tax		**(1)**	(4)
	Income tax recovery (expense)	**-**	-
Total net of tax		$ **(1)**	$ (4)
Net change in unrecognized pension and post-retirement benefit costs			
Actuarial losses (gains)	Operating, maintenance and general ("OM&G")	$ **40**	$ 41
Past service costs (gains)	OM&G	**(8)**	(9)
Amounts reclassified into obligations	Pension and post-retirement benefits	**11**	(17)
Total before tax		**43**	15
	Income tax recovery (expense)	**1**	(3)
Total net of tax		$ **44**	$ 12
Total reclassifications out of AOCI, net of tax, for the period		$ **51**	$ 65

13. INVENTORY

Inventory consisted of the following:

As at millions of Canadian dollars	**December 31 2017**	December 31 2016
Fuel	**$ 180**	$ 235
Materials	**216**	215
Emission credits (1)	**22**	22
	$ 418	$ 472

(1)The NEGG Facilities are subject to the Acid Rain Program for sulphur dioxide emissions and the Regional Greenhouse Gas Initiative for carbon dioxide emissions. The emissions credits inventory balance represents the credits purchased to offset the other current liabilities and other long-term liabilities associated with these programs.

14. DERIVATIVE INSTRUMENTS

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

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**December 31 2017**	December 31 2016	**December 31 2017**	December 31 2016
Cash flow hedges				
Power swaps	**$ 5**	$ 10	**$ 2**	$ 5
Foreign exchange forwards	**2**	-	**5**	22
	7	10	**7**	27
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**137**	83	**10**	9
Power purchases	**5**	7	**3**	4
Natural gas purchases and sales	**6**	33	**7**	2
Heavy fuel oil purchases	**15**	10	**4**	7
Foreign exchange forwards	**32**	106	**4**	-
	195	239	**28**	22
HFT derivatives				
Power swaps and physical contracts	**125**	47	**162**	71
Natural gas swaps, futures, forwards, physical contracts	**105**	111	**294**	484
	230	158	**456**	555
Other derivatives				
Interest rate swap	**2**	-	**-**	1
Foreign exchange forwards	**-**	-	**-**	1
	2	-	**-**	2
Total gross current derivatives	**434**	407	**491**	606
Impact of master netting agreements with intent to settle net or simultaneously	**(181)**	(131)	**(181)**	(131)
	253	276	**310**	475
Current	**141**	145	**227**	325
Long-term	**112**	131	**83**	150
Total derivatives	**$ 253**	$ 276	**$ 310**	$ 475

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 millions of Canadian dollars	**December 31 2017**	December 31 2016	**December 31 2017**	December 31 2016
Regulatory deferral	**$ 14**	$ 10	**$ 14**	$ 10
HFT derivatives	**167**	121	**167**	121
Total impact of master netting agreements with intent to settle net or simultaneously	**$ 181**	$ 131	**$ 181**	$ 131

Cash Flow Hedges

The Company enters into various derivatives designated as cash flow hedges. Emera enters into power swaps to limit Bear Swamp's exposure to purchased power prices. The Company also enters into foreign exchange forwards to hedge the currency risk for revenue streams denominated in foreign currency for Brunswick Pipeline.

The amounts related to cash flow hedges recorded in income and AOCI consisted of the following:

For the millions of Canadian dollars			**2017**			Year ended December 31 2016
	Power swaps	**Interest rate swaps**	**Foreign exchange forwards**	Power swaps	Interest rate swaps	Foreign exchange forwards
Realized gain (loss) in non-regulated fuel for generation and purchased power	**3**	**-**	**-**	2	-	-
Realized gain (loss) in operating revenue – Regulated	**-**	**-**	**(10)**	-	-	(12)
Realized gain (loss) in income from equity investments	**-**	**-**	**-**	-	(1)	-
Total gains (losses) in Net income	**$ 3**	**$ -**	**$ (10)**	$ 2	$ (1)	$ (12)

As at millions of Canadian dollars			**2017**			December 31 2016
	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)**	$ 2	$ -	$ (22)

The Company expects $5 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, 2017, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	**2018**	2019	2020	2021	2022
Foreign exchange forwards (USD) sales	$ **45**	$ 30	$ 30	$ -	$ -

Regulatory Deferral

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	**2017** **Commodity swaps and forwards**	**Physical natural gas purchases and sales**	**Foreign exchange forwards**	Year ended December 31 2016 Commodity swaps and forwards	Physical natural gas purchases and sales	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ (33)**	**$ (1)**	**$ (4)**	$ 40	$ -	$ (2)
Unrealized gain (loss) in regulatory liabilities	**83**	**1**	**(30)**	101	(1)	(30)
Realized (gain) loss in regulatory assets	**-**	**-**	**-**	-	-	12
Realized (gain) loss in regulatory liabilities	**(2)**	**-**	**-**	-	-	(8)
Realized (gain) loss in inventory (1)	**(17)**	**-**	**(30)**	5	-	(44)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(3)**	**-**	**(14)**	17	(1)	(18)
Total change derivative instruments	**$ 28**	**$ -**	**$ (78)**	$ 163	$ (2)	$ (90)

(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, 2017, 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:

millions	2018 Purchases	2019-2021 Purchases
Coal (metric tonnes)	1	1
Natural Gas (Mmbtu)	30	14
Heavy fuel oil (bbls)	-	1

Foreign Exchange Swaps and Forwards

As at December 31, 2017, 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:

	2018	2019-2020
Foreign exchange contracts (millions of US dollars)	$ 144	$ 156
Weighted average rate	1.1061	1.2001
% of USD requirements	79%	40%

The Company reassesses foreign exchange forecasted periodically and will enter into additional hedges or unwind existing hedges, as required.

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 **2017**	2016
Power swaps and physical contracts in non-regulated operating revenues	**$ 7**	$ (1)
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**401**	69
Natural gas swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**10**	(7)
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**2**	-
Foreign exchange options in other income (expenses), net	**-**	(2)
	$ 420	$ 59

As at December 31, 2017, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2018	2019	2020	2021	2022
Natural gas purchases (Mmbtu)	325	134	62	44	41
Natural gas sales (Mmbtu)	250	56	21	8	2
Power purchases (MWh)	7	2	-	-	-
Power sales (MWh)	8	1	-	-	-
Foreign exchange options (USD)	$ 2	$ 4	$ -	$ -	$ -

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		**2017**	Year ended December 31	2016
	Interest rate swaps	**Foreign exchange forwards**	Interest rate swaps	Foreign exchange forwards
Realized gain (loss) in other income (expense)	**$ -**	**$ -**	$ -	$ (87)
Unrealized gain (loss) in interest expense, net	**2**	**-**	2	-
Total gains (losses) in net income	**$ 2**	**$ -**	$ **2**	$ **(87)**

As at December 31, 2017, 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.

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, 2017, the maximum exposure the Company has to credit risk is $1,148 million (2016 - $1,019 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, 2017 was $247 million (2016 - $271 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, 2017, the Company had $90 million (2016 - $104 million) in financial assets, considered to be past due, which have been outstanding for an average 69 days. The fair value of these financial assets is $78 million (2016 - $91 million), the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric and gas revenue.

Concentration Risk

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

As at	**December 31, 2017**			December 31, 2016		
		millions of Canadian dollars	**% of total exposure**		millions of Canadian dollars	% of total exposure
Receivables, net						
Regulated utilities						
Residential	**$**	**326**	**23%**	$	315	24%
Commercial		**161**	**11%**		170	13%
Industrial		**46**	**3%**		38	3%
Other		**96**	**7%**		69	5%
		629	**44%**		592	45%
Trading group						
Credit rating of A- or above		**55**	**4%**		52	4%
Credit rating of BBB- to BBB+		**61**	**4%**		60	5%
Not rated		**96**	**7%**		57	4%
		212	**15%**		169	13%
Other accounts receivable		**300**	**22%**		253	20%
		1,141	**81%**		1,014	78%
Derivative Instruments (current and long-term)						
Credit rating of A- or above		**207**	**15%**		252	20%
Credit rating of BBB- to BBB+		**10**	**1%**		1	0%
Not rated		**36**	**3%**		23	2%
		253	**19%**		276	22%
	$	**1,394**	**100%**	$	1,290	100%

Cash Collateral

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

As at millions of Canadian dollars		**December 31 2017**		December 31 2016
Cash collateral provided to others	**$**	**119**	$	91
Cash collateral received from others		**99**		52

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 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 falling below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at December 31, 2017, the total fair value of these derivatives, in a liability position, was $310 million (December 31, 2016 – $475 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.

15. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exemption (refer to note 1), and uses a market approach to do so. The three levels of the fair value hierarchy are defined as follows:

Level 1 - 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 - 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 - 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.

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

As at				December 31, 2017
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash flow hedges				
Power swaps	**$ 5**	**$ -**	**$ -**	**$ 5**
Foreign exchange forwards	**-**	**2**	**-**	**2**
	5	**2**	**-**	**7**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**127**	**-**	**127**
Power purchases	**5**	**-**	**-**	**5**
Natural gas purchases and sales	**-**	**5**	**-**	**5**
Heavy fuel oil purchases	**4**	**8**	**-**	**12**
Foreign exchange forwards	**-**	**32**	**-**	**32**
	9	**172**	**-**	**181**
HFT derivatives				
Power swaps and physical contracts	**-**	**3**	**9**	**12**
Natural gas swaps, futures, forwards, physical contracts and related transportation	**-**	**26**	**25**	**51**
	-	**29**	**34**	**63**
Other derivatives				
Interest rate swap	**-**	**2**	**-**	**2**
	-	**2**	**-**	**2**
Total assets	**14**	**205**	**34**	**253**
Liabilities				
Cash flow hedges				
Power swaps	**2**	**-**	**-**	**2**
Foreign exchange forwards	**-**	**5**	**-**	**5**
	2	**5**	**-**	**7**
Regulatory deferral				
Commodity swaps and forwards				
Power purchases	**3**	**-**	**-**	**3**
Natural gas purchases and sales	**5**	**1**	**-**	**6**
Foreign exchange forwards	**-**	**4**	**-**	**4**
	8	**5**	**-**	**13**
HFT derivatives				
Power swaps and physical contracts	**49**	**5**	**(4)**	**50**
Natural gas swaps, futures, forwards and physical contracts	**6**	**47**	**187**	**240**
	55	**52**	**183**	**290**
Total liabilities	**65**	**62**	**183**	**310**
Net assets (liabilities)	**$ (51)**	**$ 143**	**$ (149)**	**$ (57)**

As at				December 31, 2016
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Cash flow hedges				
Power swaps	$ 10	$ -	$ -	$ 10
	10	-	-	10
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	74	-	74
Power purchases	7	-	-	7
Natural gas purchases and sales	8	25	-	33
Heavy fuel oil purchases	3	5	1	9
Foreign exchange forwards	-	106	-	106
	18	210	1	229
HFT derivatives				
Power swaps and physical contracts	(7)	1	-	(6)
Natural gas swaps, futures, forwards, physical contracts and related transportation	-	4	39	43
	(7)	5	39	37
Total assets	21	215	40	276
Liabilities				
Cash flow hedges				
Power swaps	4	-	-	4
Foreign exchange forwards	-	23	-	23
	4	23	-	27
Regulatory deferral				
Power purchases	4	-	-	4
Heavy fuel oil purchases	-	6	-	6
Natural gas purchases and sales	1	1	-	2
	5	7	-	12
HFT derivatives				
Power swaps and physical contracts	12	5	-	17
Natural gas swaps, futures, forwards and physical contracts	4	24	389	417
	16	29	389	434
Other derivatives				
Foreign exchange forwards	-	1	-	1
Interest rate swaps	-	1	-	1
	-	2	-	2
Total liabilities	25	61	389	475
Net assets (liabilities)	$ (4)	$ 154	$ (349)	$ (199)

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2017 was as follows:

	Regulatory Deferral		*HFT Derivatives*		
millions of Canadian dollars	Oil financial derivatives	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1, 2017	$ 1	$ -	$ -	$ 39	$ 40
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	-	(1)	-	-	(1)
Unrealized gains (losses) included in regulatory assets or liabilities	(1)	1	-	-	-
Total realized and unrealized gains (losses) included in non-regulated operating revenues	-	-	9	1	10
Net transfers out of Level 3	-	-	-	(15)	(15)
Balance, December 31, 2017	$ -	$ -	$ 9	$ 25	$ 34

The change in the fair value of the Level 3 financial liabilities for the year ended December 31, 2017 was as follows:

	Regulatory Deferral		*HFT Derivatives*		
millions of Canadian dollars	Oil financial derivatives	Physical natural gas purchases and sales	Power	Natural gas	Total
Balance, January 1, 2017	$ -	$ -	$ -	$ 389	$ 389
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	-	(1)	-	-	(1)
Increase (reduction) in benefit included in non-regulated fuel for generation and purchased power	-	1	-	-	1
Total realized and unrealized gains (losses) included in non-regulated operating revenues	-	-	(5)	(206)	(211)
Net transfers into Level 3	-	-	1	4	5
Balance, December 31, 2017	$ -	$ -	$ (4)	$ 187	$ 183

The Company evaluates the observable inputs of market data on a quarterly basis in order to determine if transfers between levels is appropriate. For the year ended December 31, 2017, transfers out of Level 3 were a result of an increase in observable inputs. For the year ended December 31, 2017, transfers into Level 3 were a result of a decrease in observable inputs.

Significant unobservable inputs used in the fair value measurement of Emera's natural gas and power derivatives include 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, 2017**	
millions of Canadian dollars		**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets						
HFT derivatives –		**1**	Modelled pricing	Third-party pricing	\$24.88-\$117.90	\$92.93
Power swaps and physical contracts				Probability of default	0.00%-0.01%	0.00%
				Discount rate	0.00%-0.13%	0.00%
		8	Modelled pricing	Third-party pricing	\$63.48-\$117.00	\$102.68
				Correlation factor	0.94%-0.99%	0.96%
				Probability of default	0.00%-0.00%	0.00%
				Discount rate	0.00%-0.00%	0.00%
HFT derivatives –		**18**	Modelled pricing	Third-party pricing	\$2.06-\$8.24	\$3.61
Natural gas swaps, futures,				Probability of default	0.00%-0.05%	0.00%
forwards, physical contracts				Discount rate	0.00%-0.29%	0.06%
and related transportation		**7**	Modelled pricing	Third-party pricing	\$2.04-\$12.52	\$6.42
				Basis adjustment	0.08%-0.71%	0.52%
				Probability of default	0.00%-0.00%	0.00%
				Discount rate	0.00%-0.09%	0.01%
Total assets	**\$**	**34**				
Liabilities						
HFT derivatives –	**\$**	**(6)**	Modelled pricing	Third-party pricing	\$24.88-\$117.90	\$95.46
Power swaps and				Own credit risk	0.00%-0.01%	0.00%
physical contracts				Discount rate	0.00%-0.13%	0.00%
		2	Modelled pricing	Third-party pricing	\$94.5-\$117.00	\$105.52
				Correlation factor	0.94%-0.99%	0.96%
				Probability of default	0.00%-0.00%	0.00%
				Discount rate	0.00%-0.00%	0.00%
HFT derivatives –		**172**	Modelled pricing	Third-party pricing	\$1.89-\$11.81	\$4.64
Natural gas swaps, futures,				Own credit risk	0.00%-0.00%	0.00%
forwards and physical contracts				Discount rate	0.00%-0.12%	0.02%
		15	Modelled pricing	Third-party pricing	\$2.15-\$12.52	\$8.94
				Basis adjustment	0.08%-0.71%	0.53%
				Own credit risk	0.00%-0.00%	0.00%
				Discount rate	0.00%-0.08%	0.01%
Total liabilities	**\$**	**183**				
Net assets (liabilities)	**\$**	**(149)**				

As at					December 31, 2016
millions of Canadian dollars	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets					
Regulatory deferral – Financial oil derivatives	$ 1	Modelled pricing	Third-party pricing	$69.64	$69.64
			Probability of default	0.80%	0.80%
HFT derivatives – Natural gas swaps, futures, forwards, physical contracts and related transportation	27	Modelled pricing	Third-party pricing	$1.41 - $11.87	$3.87
			Probability of default	0.00% - 0.07%	0.01%
			Discount rate	0.00% - 0.32%	0.05%
	12	Modelled pricing	Third-party pricing	$1.83 - $11.87	$6.16
			Basis adjustment	(0.11)% - 0.64%	0.39%
			Probability of default	0.00% - 0.05%	0.00%
			Discount rate	0.00% - 0.10%	0.00%
Total assets	$ 40				
Liabilities					
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	$ 386	Modelled pricing	Third-party pricing	$1.55 - $11.87	$6.26
			Own credit risk	0.00% - 0.07%	0.00%
			Discount rate	0.00% - 0.14%	0.02%
	3	Modelled pricing	Third-party pricing	$1.83 - $11.87	$5.93
			Basis adjustment	(0.11)% - 0.64%	0.27%
			Own credit risk	0.00% - 0.05%	0.01%
			Discount rate	0.00% - 0.10%	0.01%
Total liabilities	389				
Net assets (liabilities)	$ (349)				

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

As at millions of Canadian dollars	Carrying Amount	Fair Value	Level 1	Level 2	Level 3	Total
December 31, 2017	**$ 13,881**	**$ 15,217**	**$ 69**	**$ 14,346**	**$ 802**	**$ 15,217**
December 31, 2016	$ 14,744	$ 15,723	$ 78	$ 14,843	$ 802	$ 15,723

The fair value of long-term debt instruments, classified as Level 1 in the fair value hierarchy, are valued using unadjusted quoted closing market prices that are traded in active markets.

Those classified as Level 2 are valued either by using recent quoted market prices for the instrument where the instrument is not frequently traded, by using quoted closing market prices for similar issues that are frequently traded in an active market or by using quoted market prices and applying estimated credit spreads, provided by third-party pricing services, to the par value of the security.

Those classified as Level 3 are valued by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality.

The Company has designated $1.2 billion United States dollar denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in United States dollar denominated operations. An after-tax foreign currency gain of $97 million was recorded in Other Comprehensive Income for the year ended December 31, 2017 (2016 – $49 million loss after-tax). There was no ineffectiveness for the year ended December 31, 2017 (2016 – nil).

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.

16. 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 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.

Regulatory Assets and Liabilities

Regulatory assets and liabilities consisted of the following:

As at millions of Canadian dollars		**December 31 2017**		December 31 2016
Regulatory assets				
Deferred income tax regulatory assets	**$**	**667**	$	632
Pension and post-retirement medical plan		**345**		373
Storm reserve		**59**		-
Environmental remediations		**41**		49
Unamortized defeasance costs		**32**		39
2015 demand side management ("DSM") deferral		**28**		32
GBPC Hurricane Matthew restoration		**28**		28
Stranded cost recovery		**25**		27
Cost-recovery clauses		**17**		12
Deferrals related to derivative instruments		**15**		15
Debt basis adjustment		**13**		19
Deferred bond refinancing costs		**7**		9
Other		**99**		87
	$	**1,376**	$	1,322
Current	**$**	**138**	$	80
Long-term		**1,238**		1,242
Total regulatory assets	**$**	**1,376**	$	1,322
Regulatory liabilities				
Deferred income tax regulatory liabilities		**1,116**		26
Accumulated reserve - cost of removal		**894**		990
Deferrals related to derivative instruments		**182**		230
Regulated fuel adjustment mechanism		**177**		94
Cost-recovery clauses		**51**		153
Self-insurance fund (notes 7 and 32)		**28**		30
Bill reduction credit		**4**		10
Storm reserve		**-**		75
Other		**16**		31
	$	**2,468**	$	1,639
Current	**$**	**226**	$	362
Long-term		**2,242**		1,277
Total regulatory liabilities	**$**	**2,468**	$	1,639

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.

As a result of the US Tax Cuts and Jobs Act of 2017 ("the Act") being enacted during 2017, the Company has provisionally revalued its United States deferred income tax assets and liabilities based on the new 21 per cent tax rate. The Company has reduced its US regulated net deferred income tax liabilities by $1.1 billion and recorded an equivalent regulatory liability since the benefit of lower US taxes is expected to be returned to customers over time as required by the Act or by order of the applicable regulator. The Company is still analyzing certain aspects of the Act, which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts. Further adjustments, if any, will be recorded by the Company during the measurement period in 2018 as permitted by SEC Staff Accounting Bulletin 118, Income tax Accounting Implications of the Tax Cuts and Jobs Act.

Pension and Post-Retirement Medical Plan

This asset is primarily related to the deferred costs of pension and post-retirement benefits at Emera Florida and New Mexico. It is included in rate base and earns a rate of return as permitted by the FPSC or NMPRC, as applicable. It is amortized over the remaining service life of plan participants.

Storm Reserve

The storm reserve is for hurricanes and other named storms that cause significant damage to Tampa Electric's system. Tampa Electric can petition the FPSC to seek recovery of restoration costs over a 12-month period, or longer, as determined by the FPSC, as well as replenish the reserve. As a result of several named storms including Tropical Storm Colin, Hurricane Hermine and Hurricane Matthew, Tampa Electric incurred $10 million USD of storm costs in 2016. In the first quarter of 2017, Tampa Electric applied the $10 million USD of storm costs to the storm reserve, reducing the balance in the storm reserve to $46 million USD.

On September 10, 2017, Tampa Electric was impacted by Hurricane Irma. The estimated cost of restoration is $105 million USD, of which $93 million USD was charged to the storm reserve, $8 million USD was charged to capital expenditures and $4 million USD was charged to OM&G. The $93 million USD charged to the storm reserve exceeded the $46 million USD balance by $47 million USD, which has been recorded as a regulatory asset on the balance sheet. This regulated asset is included in rate base. Based on an FPSC order, if the charges to the storm reserve exceed the account balance, the excess is to be carried as a regulatory asset. Tampa Electric petitioned the FPSC on December 28, 2017 for the recovery of the estimated storm costs in excess of the reserve for several named storms, including Hurricane Irma, and to replenish the balance in the reserve to the $56 million USD level that existed as of October 31, 2013. An amended petition was filed with the FPSC on January 30, 2018.

Environmental Remediations

This asset is primarily related to PGS costs associated with the environmental remediation at manufactured gas plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is based on a settlement agreement approved by the FPSC.

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, 2017, totalled $0.7 billion (2016 – $0.8 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

Effective January 1, 2015, NSPI must purchase electricity efficiency and conservation activities ("Program Costs") from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. 2015 Program Costs were deferred to a regulatory asset and are recoverable from customers over an eight-year period which began in 2016. The UARB directed EffficiencyOne to review the financing options through which they would borrow the 2015 deferral amount from a commercial lender in order to repay NSPI the amount it expended on behalf of its customers in 2015. In December 2016, EffficiencyOne secured the financing and advanced funds to NSPI to finance the 2015 DSM deferral. This was set up as a payable on the Consolidated Balance Sheets, included in current and long-term other liabilities. As NSPI collects the associated amounts from customers over the next six years, it will repay the balance to EfficiencyOne thereby reducing the liability.

Hurricane Matthew Restoration

This asset represents restoration costs incurred by GBPC in 2016 associated with Hurricane Matthew. The asset is being amortized over five years and is included in rate base. The Grand Bahama Port Authority ("GBPA") has approved full recovery of these storm restoration costs.

Stranded Cost Recovery

Due to the decommissioning of a GBPC steam turbine during 2012, the GBPA approved the recovery of a $21 million USD stranded cost through electricity rates; it is included in rate base for 2016 to 2018.

Cost Recovery Clauses

These assets and liabilities are related to TEC and NMGC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by FPSC or NMPRC, as applicable, on a dollar-for-dollar basis in the next year.

Debt Basis Adjustment

This asset represents the difference between the fair value and pre-merger carrying amounts for NMGC's long-term debt on the date TECO Energy acquired NMGC. In accordance with purchase accounting standards, NMGC's long-term debt was valued at fair value on the Consolidated Balance Sheets. In accordance with the stipulation agreement with the NMPRC, an offsetting regulatory asset was recorded in order to eliminate the effects of purchase accounting on rate payers. The asset does not earn a return and is not included in the regulatory capital structure. It is amortized over the term of the related debt instrument.

Deferrals Related to Derivative Instruments

Tampa Electric, PGS, NMGC, NSPI and GBPC defer changes in fair value of derivatives that are documented as economic hedges or that do not qualify for 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, inventory or property, plant and equipment, depending on the nature of the item being economically hedged. Tampa Electric deferrals related to derivative instruments are recovered through cost-recovery mechanisms on a dollar-for-dollar basis in the year following the settlement of the derivative position.

Deferred Bond Refinancing Costs

This asset represents Tampa Electric and NMGC costs associated with refinancing debt. It does not earn a return but is instead included in the capital structure, which is used in the calculation of the weighted average cost of capital used to determine revenue requirements. It is amortized over the term of the related debt instruments.

Accumulated Reserve – Cost of Removal

This regulatory liability represents the non-ARO Cost of Removal ("COR") reserve in Tampa Electric and NSPI. AROs are costs for legally required removal of property, plant and equipment. Non-ARO COR represent estimated funds received from customers through depreciation rates to cover future non-legally required cost of removal of property, plant and equipment, net of salvage value upon retirement, which reduces rate base for ratemaking purposes. This liability is reduced as COR are incurred and increased as depreciation is recorded for existing assets and as new assets are put into service.

Fuel Adjustment Mechanism

Differences between actual fuel costs and amounts recovered from NSPI customers through electricity rates in a given year are deferred to a fuel adjustment mechanism ("FAM") regulatory asset or liability and recovered from or returned to customers in a subsequent year. For the years 2017 to 2019, differences between actual fuel costs and fuel revenues recovered from customers will be recovered or returned to customers after 2019, as required under the *Electricity Plan Act*.

Bill Reduction Credit

This regulatory liability represents NMGC's stipulation agreement commitment to provide an annual bill reduction credit to customers of $4 million USD per year through June 30, 2018, as part of Emera's acquisition of TECO Energy.

Regulatory Environments

Emera Florida and New Mexico

Tampa Electric and PGS are regulated separately by the FPSC. Tampa Electric is also subject to regulation by the FERC. In general, the FPSC sets rates at a level that allows utilities such as Tampa Electric and PGS to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

NMGC is subject to regulation by the NMPRC. The NMPRC sets rates at a level that allows NMGC to collect total revenues equal to their cost of providing service, plus an appropriate return on invested capital.

<u>Base Rates - Tampa Electric</u>

Tampa Electric's target regulated return on equity ("ROE") range is 9.25 per cent to 11.25 per cent. Based on a Stipulation and Settlement Agreement in 2013 Tampa Electric received a revenue increase of $110 million USD effective January 17, 2017, the date Tampa Electric's Polk Power Station went into service. The agreement also provided that Tampa Electric could not file for additional rate increases until 2017 (to be effective no sooner than January 1, 2018), unless its earned ROE fell below 9.25 per cent before that time. If its earned ROE rose above 11.25 per cent any party to the agreement other than Tampa Electric could seek a review of its base rates. Under the agreement, the allowed equity in the capital structure is 54 per cent from investor sources of capital.

In September 2017, Tampa Electric announced its intention to invest approximately $850 million USD over four years in new utility-scale solar photovoltaic projects across its service territory. A settlement agreement was filed with the FPSC requesting a solar base rate adjustment ("SoBRA") that provides for the recovery, upon in-service, of up to 600 MW of investments in utility-scale solar projects that will be phased in from late 2018 through early 2021. The Tampa Electric settlement agreement contains a provision whereby the impacts of tax reform will be offset by a reduction in base rates within 120 days of when tax reform becomes law. On November 6, 2017, the FPSC approved the settlement agreement that replaced the existing 2013 agreement and extended it another four year years through 2021. On December 12, 2017, TEC filed its petition along with supporting tariffs demonstrating the cost-effectiveness of the September 1, 2018 SoBRA representing 145 MW and $26 million in estimated revenue requirements. A decision by the FPSC to approve the tariffs on the first SoBRA filing is anticipated in the spring of 2018.

On January 30, 2018, Tampa Electric filed with the FPSC a settlement agreement which, if approved, will allow Tampa Electric to net the estimated amount of storm cost recovery against the utility's estimated 2018 tax reform benefits. Any difference would be trued up and recovered from or returned to customers in 2019. Beginning in January 2019 Tampa Electric would reflect the full impact of tax reform on Tampa Electric's base rates, provided that the FPSC's determinations have been finalized. A decision is expected in March 2018.

Base Rates - PGS

Prior to 2016, PGS's base rates were based upon an ROE of 10.75 per cent, with a range between 9.75 per cent and 11.75 per cent.

In December 2016, PGS entered into a settlement agreement with the Office of Public Counsel ("OPC") regarding its filed depreciation study. The settlement agreement resulted in new depreciation rates that reduce annual depreciation by $16 million USD in 2016 and accelerated the amortization of the regulated asset related to the Manufactured Gas Plant ("MGP") environmental remediation costs. In addition, the bottom of the ROE range was decreased from 9.75 per cent to 9.25 per cent. The new bottom of the range will remain until the earlier of new base rates established in PGS's next general rate proceeding or December 31, 2020. The top of the range will continue to be 11.75 per cent and the ROE of 10.75 per cent will continue to be used for the calculation of return on investment for clauses. On February 7, 2017 the FPSC approved the settlement agreement. No change in customer rates resulted from this agreement.

As part of the settlement, PGS and OPC agreed that at least $32 million USD of PGS's regulatory asset associated with the environmental liability for current and future remediation costs related to former MGP sites will be amortized over the period 2016 through 2020. At least $21 million USD will be amortized over a two year recovery period beginning in 2016. In 2017 and 2016, PGS recorded $5 million and $16 million, respectively, of this amortization expense.

The PGS settlement does not contain a provision for US tax reform. On January 9, 2018, the OPC filed a generic docket requesting the FPSC to address tax reform benefits for all utilities in Florida without an existing tax reform settlement provision, including PGS.

Base Rates - NMGC

NMGC's base rates were established in 2012 through a settlement agreement. As a condition of the 2016 NMPRC order (the "Order") approving the acquisition of TECO Energy, NMGC will not seek an increase in base rates to be effective prior to December 31, 2017, and NMGC will continue to provide an annual bill reduction credit of $4 million USD through June 30, 2018. NMGC plans to file a rate case in 2018.

NSPI

NSPI is a public utility as defined in the Public Utilities Act of Nova Scotia (the "Public Utilities Act") and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities 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 ROE range for 2017 and 2016 was 8.75 per cent to 9.25 per cent based on an actual five quarter 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.

In December 2015, the Province enacted the *Electricity Plan Implementation (2015) Act, ("Electricity Plan Act")*, which required NSPI to file a three-year stability plan for fuel costs and a General Rate Application ("GRA") for non-fuel costs if required. In July 2016, the UARB approved a Consensus Agreement between NSPI and customer representatives related to the Rate Stability Plan for fuel costs for 2017 through 2019 which resulted in an average annual increase of 1.1 per cent for each of these three years. Subsequently, certain customer representatives requested changes resulting in amended rates that were approved by the UARB in November 2016 and result in an average annual rate increase of 1.5 per cent for each of these three years.

In December 2016, the UARB approved NSPI's application to refund over-recovered fuel costs from 2016 to customers. The over-recovered 2016 fuel costs of $36 million were refunded to customers through a one-time credit on their bills in 2017 and allocated to customers based on their individual electricity usage in 2016. The amount refunded to customers includes 2016 excess non-fuel revenues of $5 million.

On September 11, 2017, the UARB approved NSPI's interim assessment payment to NSPML of the costs associated with the Maritime Link starting when the Maritime Link is in service. The Maritime Link completed commissioning and entered service on January 15, 2018. In response to the delayed timing of energy delivery from the Muskrat Falls project, the approved interim assessment payment reflects NSPML's proposal to reduce the assessment by deferring $53 million in each of 2018 and 2019, related to depreciation and amortization expenses. As these amounts are included in NSPI's 2017, 2018 and 2019 fuel rates and are being recovered from customers, NSPI will provide a one-time credit to customers, including interest, in 2018 of approximately $17 million, 2019 of approximately $36 million and 2020 of approximately $53 million, as the payments from NSPI to NSPML are not required.

NSPI is also required to hold back $10 million from the interim assessment payment to NSPML in 2018 and 2019. The release of such amounts is subject to providing evidence to the UARB that at least that amount of benefit from the Maritime Link has been realized for NSPI customers in that year. If the $10 million in benefits is realized, the UARB will direct NSPI to pay the $10 million to NSPML for that year. If not realized, then the UARB will direct NSPI to pay to NSPML only that portion that is realized and the balance will be refunded to customers through NSPI's FAM.

Emera Maine

Emera Maine's distribution operations and stranded cost recoveries are regulated by the Maine Public Utilities Commission ("MPUC"). The transmission operations are regulated by the FERC. The rates for these three elements are established in distinct regulatory proceedings.

Distribution Operations

Emera Maine's distribution businesses operate under a traditional cost-of-service regulatory structure, and distribution rates are set by the MPUC. On December 21, 2016, Emera Maine's distribution rates increased by 3.75 per cent, including the recovery, over five years, of approximately $4 million USD of costs associated with a major storm in Maine in 2014. Also, effective December 21, 2016, the allowed ROE was reduced by 0.55 per cent to 9.00 per cent on a common equity component of 49 per cent.

Transmission Operations

Emera Maine's transmission operations are split between two districts; Bangor Hydro District and Maine Public Service ("MPS"). Bangor Hydro District local transmission rates 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 for Bangor Hydro District local transmission operations for 2017 and 2016 is 10.57 per cent. Bangor Hydro District's bulk transmission assets are managed by ISO-New England ("ISO-NE") as part of a region-wide pool of assets. The allowed ROE range for Bangor Hydro bulk transmission assets is 11.07 to 11.74 per cent for 2017 and 2016.

MPS District local transmission rates 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. The current allowed ROE for transmission operations is 9.6 per cent (2016 – 10.2 per cent).

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.

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 the Fair Trading Commission ("The Rules"), Barbados, an independent regulator. The Rules give the Fair Trading Commission, Barbados utility regulation functions. 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 was 10 per cent for 2017 and 2016.

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.

Grand Bahama Power Company Limited

GBPC is a vertically integrated utility and sole provider of electricity on Grand Bahama Island. The 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 was 8.8 per cent for 2017 and 2016. In December 2017 the GBPA approved GBPC's regulated return on rate base of 8.5 per cent for 2018.

In December 2016, the GBPA approved that over a five-year period, 2017 to 2021, the all-in rate for electricity (fuel and base rates) will be held at 2016 levels. Any over-recovery of fuel costs during this period will be applied to the Hurricane Matthew regulatory deferral, until such time as the deferral is recovered. Should GBPC recover funds in excess of the Hurricane Matthew regulatory deferral, the excess will be placed in a new storm reserve. If balances remain within the Hurricane Matthew deferral at the end of five years, GBPC will have the opportunity to request recovery from customers in future rates.

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 was 15 per cent for 2017 and 2016.

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.

On September 19, 2017, Dominica experienced unprecedented damage as a result of Hurricane Maria, facing sustained winds of over 175 miles per hour. All 36,000 of Domlec's customers lost power following the storm as the Company's transmission and distribution assets were significantly impacted. Domlec has implemented a restoration plan. Domlec maintains insurance for its generation fleet and, as with most utilities, transmission and distribution networks are self-insured. Management has completed its damage assessment and an estimated impairment provision has been recorded at December 31, 2017. Emera's portion of the estimated impairment provision is immaterial.

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.

17. 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. Intercompany balances and intercompany 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, as discussed in note 1. All material amounts are under normal interest and credit terms.

Significant transactions between Emera and its associated companies are:

- Natural gas transportation capacity revenues from M&NP reported in the Consolidated Statements of Income. Revenues from M&NP, reported in Operating revenue - non-regulated, totalled $28 million for the year ended December 31, 2017 (2016 - $29 million).

- Transmission construction revenues from NSPML reported in the Consolidated Statements of Income. Revenues from NSPML, reported in Operating revenues, Non-regulated, totalled $17 million for the year ended December 31, 2017 (2016 - $18 million).

There are no significant receivables or payables between Emera and its associated companies reported on Emera's Consolidated Balance Sheets as at December 31, 2017 and December 31, 2016.

18. RECEIVABLES AND OTHER CURRENT ASSETS

Receivables and other current assets consisted of the following:

As at millions of Canadian dollars		**December 31 2017**		December 31 2016
Customer accounts receivable – billed	**$**	**805**	$	715
Customer accounts receivable – unbilled		**278**		270
Allowance for doubtful accounts		**(12)**		(13)
Other receivables		**70**		42
Capitalized transportation capacity (1)		**89**		190
Prepaid expenses		**59**		57
Due from related parties		**5**		16
Net investment in direct financing lease		**8**		8
Income tax receivable		**24**		33
Other		**-**		5
	$	**1,326**	$	1,323

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

19. 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 2017**		December 31 2016
Generation	3 to 131	**$**	**11,010**	$	10,553
Transmission	15 to 80		**2,786**		2,799
Distribution	4 to 80		**5,660**		5,715
Gas transmission and distribution	7 to 85		**2,867**		2,895
General plant and other	3 to 60		**1,874**		1,711
Total cost			**24,197**		23,673
Less: Accumulated depreciation			**(7,824)**		(7,787)
			16,373		15,886
Construction work in progress			**622**		1,404
Net book value		**$**	**16,995**	$	17,290

20. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees. In addition, the Company provides non-pension benefits for its retirees. These plans cover employees in Nova Scotia, New Brunswick, Newfoundland and Labrador, Florida, Maine, Connecticut, Massachusetts, Rhode Island, New Mexico, Barbados, Dominica and Grand Bahama Island.

Benefit Obligation and Plan Assets

The changes in benefit obligation and plan assets, and the funded status for all plans were as follows:

For the millions of Canadian dollars	2017		Year ended December 31 2016	
Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Balance, January 1	**$ 2,607**	**$ 358**	$ 1,520	$ 88
Addition of TECO Energy, July 1, 2016	**-**	**-**	1,035	277
Service cost	**49**	**5**	35	4
Plan participant contributions	**8**	**4**	8	-
Interest cost	**99**	**14**	79	9
Plan amendments	**-**	**-**	-	2
Benefits paid	**(129)**	**(27)**	(94)	(16)
Actuarial losses	**171**	**25**	(2)	(12)
Special termination	**(35)**	**-**	-	-
Foreign currency translation adjustment	**(87)**	**(23)**	26	6
Balance, December 31	**2,683**	**356**	2,607	358
Change in plan assets				
Balance, January 1	**2,208**	**39**	1,300	6
Addition of TECO Energy, July 1, 2016	**-**	**-**	830	29
Employer contributions	**109**	**27**	49	17
Plan participant contributions	**8**	**4**	8	-
Benefits paid	**(129)**	**(27)**	(94)	(16)
Actual return on assets, net of expenses	**313**	**5**	93	2
Special termination	**(34)**	**-**	**-**	**-**
Foreign currency translation adjustment	**(67)**	**(3)**	22	1
Balance, December 31	**2,408**	**45**	2,208	39
Funded status, end of year	**$ (275)**	**$ (311)**	$ (399)	$ (319)

Plans with PBO/APBO in excess of plan assets

The aggregate financial position for all pension plans where the PBO or, for post-retirement benefit plans, the APBO exceeds the plan assets for the years ended December 31 is as follows:

millions of Canadian dollars	2017		2016	
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 2,655**	**$ 325**	$ 2,579	$ 358
Fair value of plan assets	**2,370**	**6**	2,171	39
Funded status	**$ (285)**	**$ (319)**	$ (408)	$ (319)

Plans with Accumulated Benefit Obligation ("ABO") in excess of plan assets

The ABO for the defined benefit pension plans was $2,561 million as at December 31, 2017 (2016 – $2,489 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 is as follows:

millions of Canadian dollars	2017	2016
	Defined benefit pension plans	Defined benefit pension plans
ABO	**$ 1,608**	$ 2,462
Fair value of plan assets	**1,409**	2,171
Funded status	**$ (199)**	$ (291)

Balance Sheet

The amounts recognized in the Consolidated Balance Sheets consisted of the following:

As at millions of Canadian dollars		**December 31 2017**		December 31 2016
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Current liabilities	**$ (23)**	**$ (18)**	$ (41)	$ (17)
Long-term liabilities	**(264)**	**(295)**	(367)	(302)
Other asset (non-current)	**10**	**-**	9	-
Amount included in deferred tax asset	**15**	**1**	16	(1)
AOCL (AOCI) and regulatory assets after-tax adjustment	**548**	**73**	620	45
Net amount recognized at end of year	**$ 286**	**$ (239)**	$ 237	$ (275)

Amounts recognized in AOCI and Regulatory assets

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCI or regulatory assets. Unamortized net losses and past service costs as at the acquisition date for TECO Energy's regulated companies were recorded as regulatory assets. The following table summarizes the change in AOCI and regulatory assets:

millions of Canadian dollars	Regulatory assets	Actuarial losses (gains)	Past service (gains) costs
Defined Benefit Pension Plans			
Balance, January 1, 2017	$ 309	$ 330	$ (3)
Amortized in current period	(17)	(38)	-
Current year addition to AOCL or regulatory assets	(10)	(8)	-
Balance, December 31, 2017	$ 282	$ 284	$ (3)
Non-pension benefits plans			
Balance, January 1, 2017	$ 48	$ 15	$ (19)
Amortized in current period	1	(2)	8
Current year addition to AOCL (AOCI) or regulatory assets	25	(2)	-
Balance, December 31, 2017	$ 74	$ 11	$ (11)

		2017		2016
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Actuarial losses	**$ 284**	**$ 11**	$ 330	$ 15
Past service (gains)	**(3)**	**(11)**	(3)	(19)
Regulatory assets	**282**	**74**	309	48
Total AOCL (AOCI) and regulatory assets on a pre-tax basis	**563**	**74**	636	44
Amount included in deferred tax asset	**(15)**	**(1)**	(16)	1
Net amount in AOCL (AOCI) and regulatory assets after-tax adjustment	**$ 548**	**$ 73**	$ 620	$ 45

Benefit cost components

Emera's net periodic benefit cost included the following:

As at millions of Canadian dollars		2017		Year ended December 31 2016
	Defined benefit pension plans	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 49**	**$ 5**	$ 35	$ 4
Interest cost	**99**	**14**	79	9
Expected return on plan assets	**(129)**	**(3)**	(97)	(1)
Current year amortization of:				
Actuarial losses	**38**	**2**	42	2
Past service costs (gains)	**-**	**(8)**	(1)	(8)
Regulatory assets (liability)	**17**	**(1)**	9	-
Settlement, curtailments	**(1)**	**-**	-	-
Total	**$ 73**	**$ 9**	$ 67	$ 6

The expected return on plan assets is determined based on the market-related value of plan assets of $2,153 million as at January 1, 2017 (2016 – $1,180 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	30%	to	55%

Non-Canadian Pension Plans

Asset Class	Target Range at Market Weighted average		
Short-term securities	47%	to	52%
Equities	48%	to	53%

Pension Plan assets are overseen by the respective Management Pension Committees in the sponsoring companies. All pension investments are in accordance with policies approved by the respective Board of Directors of each sponsoring company.

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

As at millions of Canadian dollars	NAV	Level 1	Level 2	Total	December 31, 2017 Percentage
Cash and cash equivalents	-	$ 32	-	$ 32	1 %
Net in-transits	-	(36)	-	(36)	(1)%
Equity Securities:					
Canadian equity		214		214	9 %
US equity	-	390	-	390	16 %
Other equity	-	197		197	8 %
Fixed income securities:					
Government	-	-	$ 72	72	3 %
Corporate	-	-	56	56	2 %
Other	-	5	-	5	- %
Other			4	4	- %
Open-ended investments measured at NAV (1)	$ 1,065	-		1,065	44 %
Common collective trusts measured at NAV (2)	409	-	-	409	18 %
Total	$ 1,474	$ 802	$ 132	$ 2,408	100 %

(1) NAV investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds. NAV's are calculated daily and the funds honor subscription and redemption activity regularly.
(2) The common collective trusts are private funds valued at NAV. The NAVs are calculated based on bid prices of the underlying securities. Since the prices are not published to external sources, NAV is used as a practical expedient. Certain funds invest primarily in equity securities of domestic and foreign issuers while others invest in long duration U.S. investment grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The funds honor subscription and redemption activity regularly.

As at millions of Canadian dollars	NAV	Level 1	Level 2	Total	December 31, 2016 Percentage
Cash and cash equivalents	-	$ 31	$ -	31	1 %
Net in-transits	-	(42)	-	(42)	(2)%
Equity securities:					
Canadian equity	-	192	-	192	9 %
US equity	-	303	-	303	14 %
Other equity	-	243	-	243	11 %
Fixed Income securities:					
Government	-	-	47	47	2 %
Corporate	-	-	53	53	2 %
Other	-	5	14	19	1 %
Open-ended investments measured at NAV (1)	$ 1,132	-	-	1,132	51 %
Common collective trusts measured at NAV (2)	230	-	-	230	11%
Total	$ 1,362	$ 732	$ 114	2,208	100%

(1) NAV investments are open-ended registered and non-registered mutual funds, collective investment trusts, or pooled funds. NAV's are calculated daily and the funds honor subscription and redemption activity regularly.
(2) The common collective trusts are private funds valued at NAV. The NAVs are calculated based on bid prices of the underlying securities. Since the prices are not published to external sources, NAV is used as a practical expedient. Certain funds invest primarily in equity securities of domestic and foreign issuers while others invest in long duration U.S. investment grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The funds honor subscription and redemption activity regularly.

Refer to note 15 for more information on the fair value hierarchy and inputs used to measure fair value.

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 50 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.

TECO Energy and NMGC offers retirees under age 65 and their dependents a self-funded HRA medical plan identical to that offered to active TECO Energy employees. TECO Energy retirees over the age of 65 are enrolled in a Medicare Advantage plan. NMGC retirees over age 65 and their dependents receive a fixed subsidy with which they can purchase additional coverage through a medical supplement program. NMGC also provides dental benefits to retirees and spouses.

The fair values of investments as at December 31, 2017, for all Post-Retirement Benefit Plans by asset category, are as follows:

									December 31,2017
millions of Canadian dollars		**NAV**		**Level 1**		**Level 2**		**Total**	**Percentage**
Cash and cash equivalents		**-**	**$**	**1**	**$**	**-**	**$**	**1**	**2%**
Life insurance policies (1)		**-**		**-**		**39**		**39**	**87%**
Other investments measured at NAV	**$**	**5**		**-**		**-**		**5**	**11%**
Total	**$**	**5**	**$**	**1**	**$**	**39**	**$**	**45**	**100%**

(1) For valuation purposes, the life insurance policies held for the NMGC retiree medical plan are valued at the cash surrender value and are considered Level 2 assets

									December 31,2016
millions of Canadian dollars		NAV		Level 1		Level 2		Total	Percentage
Cash and cash equivalents		-	$	1	$	-	$	1	3%
Life insurance policies (1)		-		-		33		33	85%
Other investments measured at NAV	$	5		-		-		5	12%
Total	$	5	$	1	$	33	$	39	100%

(1) For valuation purposes, the life insurance policies held for the NMGC retiree medical plan are valued at the cash surrender value and are considered Level 2 assets

Refer to note 15 for more information on the fair value hierarchy and inputs used to measure fair value.

Investments in Emera

As at December 31, 2017 and 2016, the assets related to the pension funds and post-retirement benefit plans do not hold any material investments in Emera or its subsidiaries 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		
2018	$ 97	$ 25
Expected benefit payments		
2018	147	22
2019	143	23
2020	148	23
2021	157	23
2022	165	24
2023 – 2027	912	124

Assumptions

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

		2017		2016
(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	**3.55 %**	**3.65 %**	3.96 **%**	4.18 **%**
Rate of compensation increase	**3.12 %**	**3.28 %**	2.82 **%**	2.54 **%**
Health care trend - initial (next year)	**-**	**6.65 %**	-	6.78 **%**
- ultimate	**-**	**4.45 %**	-	4.45 **%**
- year ultimate reached	**-**	**2036**	-	2035
Benefit cost for year ended December 31:				
Discount rate	**3.96 %**	**4.18 %**	3.79 **%**	3.88 **%**
Expected long-term return on plan assets	**6.29 %**	**6.08 %**	6.33 **%**	4.43 **%**
Rate of compensation increase	**2.82 %**	**2.54 %**	2.88 **%**	2.56 **%**
Health care trend - initial (current year)	**-**	**6.78 %**	-	6.76 **%**
- ultimate	**-**	**4.45 %**	-	4.45 **%**
- year ultimate reached	**-**	**2035**	-	2020

Figures shown are weighted averages. Actual assumptions used 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 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 2017:

millions of Canadian dollars	Increase	Decrease
Service cost and interest cost	**$** 1	$ (1)
Accumulated post-retirement benefit obligation, December 31	19	(16)

Sensitivity Analysis for Defined Benefit Pension Plans

The impact on the 2017 benefit cost of a 25 basis point change in the discount rate and asset return assumptions is as follows:

millions of Canadian dollars	Increase	Decrease
Discount rate assumption	$ (9)	$ 9
Asset rate assumption	(6)	6

Amounts to be Amortized in the Next Fiscal Year

The following table shows the amounts from the AOCL and regulatory assets, which are expected to be recognized as part of the net periodic benefit cost in fiscal 2018:

		2018
millions of Canadian dollars	Defined benefit pension plans	Non-pension benefit plans
Actuarial gains (losses)	$ (36)	$ (2)
Past service gains	1	6
Regulatory assets	(21)	(2)
Total	$ (56)	$ 2

Defined Contribution Plan

Emera also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2017 was $23 million (2016 – $17 million), with the increase due to TECO Energy contributions being included for the full year.

21. NET INVESTMENT IN DIRECT FINANCING LEASE

Emera's net investment in direct financing lease primarily relates to Brunswick Pipeline. 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 consists of the following:

As at millions of Canadian dollars	**December 31 2017**	December 31 2016
Total minimum lease payments to be received	**$ 1,126**	$ 1,194
Less: amounts representing estimated executory costs	**(211)**	(223)
Minimum lease payments receivable	**$ 915**	$ 971
Estimated residual value of leased property (unguaranteed)	**183**	183
Less: unearned finance lease income	**(609)**	(658)
Net investment in direct financing lease	**$ 489**	$ 496
Principal due within one year (included in "Receivables and other current assets")	**8**	8
Net investment in direct financing lease – long-term	**$ 481**	$ 488

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

For the					Year ended December 31
millions of Canadian dollars	2018	2019	2020	2021	2022
Minimum lease payments to be received	$ 64	$ 64	$ 64	$ 65	$ 64
Less: amounts representing estimated executory costs	(11)	(11)	(11)	(12)	(12)
Minimum lease payments receivable	$ 53	$ 53	$ 53	$ 53	$ 52

22. GOODWILL

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

millions of Canadian dollars		2017		2016
Balance, January 1	**$**	**6,213**	$	264
Acquisition of TECO Energy as at July 1, 2016 (note 4)		**-**		5,771
Change in foreign exchange rate		**(408)**		178
Balance, December 31	**$**	**5,805**	$	6,213

Goodwill on Emera's Consolidated Balance Sheets relates to the acquisitions of TECO Energy (refer to note 4), Emera Maine and GBPC. Goodwill is subject to an annual assessment for impairment at the reporting unit level. Emera's reporting units with goodwill are Tampa Electric, PGS, New Mexico Gas, Emera Maine and GBPC.

A qualitative assessment was performed for Tampa Electric, PGS, New Mexico Gas, and GBPC, concluding that the fair value of the reporting units exceeded their carrying value, and as such, no quantitative assessment was performed.

Emera elected to bypass the qualitative assessment for Emera Maine and used a discounted cash flow analysis to determine the fair value of the reporting unit. The discounted cash flow analysis relies on management's best estimate of the reporting units' projected cash flows. It includes an estimate of terminal values based on these expected cash flows using a methodology which derives a valuation using an assumed perpetual annuity based on the entity's residual cash flows. The discount rate is a market participant rate based on a peer group of publicly traded comparable companies and represents the weighted average cost of capital of comparable companies.

The Company determined the fair value of reporting units exceed their book value and related goodwill carrying amounts at December 31, 2017 and December 31, 2016, resulting in no impairment charge. Significant assumptions used in estimating the fair value include discount and growth rates, valuation of NOLs, utility sector market performance and transactions, projected operating and capital cash flows and the calculation of the terminal value. Adverse changes in assumptions described above could result in a future material impairment of the goodwill assigned to Tampa Electric, PGS, New Mexico Gas, Emera Maine or GBPC.

23. 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		2017	Weighted-average interest rate		2016	Weighted-average interest rate
TECO Energy/TECO Finance						
Advances on revolving credit and term facilities	$	**820**	**2.58 %**	$	685	1.74 %
Tampa Electric Company						
Advances on accounts receivable and revolving credit facilities		**382**	**2.07 %**		228	1.49 %
NMGC						
Advances on revolving credit facilities		**38**	**2.47 %**		35	1.71 %
NSPI						
Bank indebtedness		**1**	**- %**		1	- %
GBPC						
Advances on revolving credit facilities		**-**	**- %**		12	5.75 %
Short-term debt	**$**	**1,241**		$	961	

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		2017		2016
TECO Energy/TECO Finance - term credit facility	2018	$	**502**	$	537
TECO Energy/TECO Finance - revolving credit facility	2022		**376**		403
Tampa Electric Company - revolving credit facility	2022		**408**		436
Tampa Electric Company - accounts receivable revolving credit facility	2018		**188**		201
Tampa Electric Company - term loan	2018		**377**		-
NMGC - revolving credit facility	2022		**157**		168
GBPC - revolving credit facility	Various		**16**		17
Total			**2,024**		1,762
Less:					
Advances under revolving credit and term facilities			**1,241**		960
Letters of credit issued within the credit facilities			**3**		3
Total advances under available facilities			**1,244**		963
Available capacity under existing agreements		$	**780**	$	799

The weighted average interest rate on outstanding short-term debt at December 31, 2017 was 2.42 per cent (2016 – 1.73 per cent).

Recent financing activities

TEC Non-revolving term loan

On November 2, 2017, TEC entered into a $300 million USD non-revolving term loan with a maturity date of November 1, 2018. The loan contains customary representations and warranties, events of default, financial and other covenants and bears interest at LIBOR plus a margin.

TECO Energy/TECO Finance Revolving Credit Facility

On March 22, 2017, TECO Energy/Finance extended the maturity date of its $300 million USD bank credit facility from December 17, 2018 to March 22, 2022 with no significant change in commercial terms from the prior agreement.

TEC Credit Facility

On March 22, 2017, TEC extended the maturity date of its $325 million USD bank credit facility from December 17, 2018 to March 22, 2022, and reduced the existing letter of credit facility to $50 million USD from $200 million USD. There were no other significant changes in commercial terms from the prior agreement.

NMGC Credit Agreement

On March 22, 2017, NMGC extended the maturity date of its $125 million USD bank credit facility from December 17, 2018 to March 22, 2022 with no significant change in commercial terms from the prior agreement.

TECO Energy/TECO Finance Term Credit Facility

On March 8, 2017, TECO Energy/Finance extended the maturity date of its $400 million USD term bank credit facility from March 14, 2017 to March 8, 2018 with no significant change in commercial terms from the prior agreement.

24. OTHER CURRENT LIABILITIES

Other current liabilities consisted of the following:

As at millions of Canadian dollars	**December 31 2017**	December 31 2016
Accrued charges	**$ 134**	$ 137
Accrued interest on long-term debt	**78**	96
Income tax payable	**1**	19
Accrued pension liability	**41**	58
Sales and other taxes payable	**11**	16
Emission credits obligations (1)	**21**	10
Other	**64**	22
	$ 350	$ 358

(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 capitalized to inventory (note 13) when purchased and subsequently applied against the emission liabilities at the end of each compliance period.

25. LONG-TERM DEBT

Bonds, notes and debentures are at fixed interest rates and are unsecured unless noted below. 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, 2017, consisted of the following:

millions of Canadian dollars	Weighted Average Interest Rate 2017 (1)	Weighted Average Interest Rate 2016 (1)	Maturity		2017		2016
Emera							
Bankers acceptances, LIBOR loans	Variable	Variable	2020	**$**	**133**	$	30
Unsecured fixed rate notes	3.50%	3.50%	2019-2023		**725**		725
Fixed to floating subordinated notes (USD)	6.75%	6.75%	2076		**1,505**		1,611
				$	**2,363**	$	2,366
Emera US Finance LP							
Unsecured senior notes (USD)	3.60%	3.60%	2019 - 2046	**$**	**4,077**	$	4,364
TECO Finance (2)							
Variable rate notes (USD)	Variable	Variable	2018	**$**	**314**	$	336
Fixed rate notes and bonds (USD)	5.15%	5.86%	2020		**376**		805
				$	**690**	$	**1,141**
Tampa Electric (3)							
Fixed rate notes and bonds (USD)	4.75%	4.90%	2018 - 2045	**$**	**2,410**	$	2,579
PGS							
Fixed rate notes and bonds (USD)	5.06%	5.06%	2018 - 2045	**$**	**328**	$	351
NMGC							
Fixed rate notes and bonds (USD)	4.53%	4.53%	2021 - 2026	**$**	**339**	$	363
NMGI							
Fixed rate notes and bonds (USD)	3.41%	3.41%	2019 - 2024	**$**	**251**	$	269
NSPI							
Commercial paper	Variable	Variable	2021	**$**	**364**	$	264
Medium term fixed rate notes	5.73%	5.73%	2019 - 2097		**1,965**		1,965
Fixed rate debenture	9.75%	9.75%	2019		**95**		95
				$	**2,424**	$	2,324
Emera Maine							
LIBOR loans and demand loans	Variable	Variable	2019	**$**	**51**	$	32
Secured fixed rate mortgage bonds (USD)	9.74%	9.74%	2020-2022		**63**		67
Unsecured senior fixed rate notes (USD)	4.15%	4.28%	2018-2047		**294**		281
				$	**408**	$	380
EBP							
Senior secured credit facility	3.08%	3.08%	2021	**$**	**248**	$	248
GBPC							
Amortizing fixed rate notes (USD)	3.77%	3.62%	2021-2022	**$**	**78**	$	63
Senior notes (USD)	7.07%	7.07%	2020-2023		**88**		67
				$	**166**	$	130
BLPC & ECI							
Secured senior notes (USD)	Variable	Variable	2021		**168**		201
Secured fixed rate senior notes (4)	5.06%	5.65%	2020 - 2028	**$**	**76**	$	81
				$	**244**	$	282
Adjustments							
Fair market value adjustment - TECO Energy acquisition (5)				**$**	**31**	$	58
Debt issuance costs					**(98)**		(111)
Amount due within one year					**(741)**		(476)
				$	**(808)**	$	(529)
Long-Term Debt				**$**	**13,140**	$	14,268

(1) Weighted average interest rate of fixed rate long-term debt.

(2) TECO Energy is a full and unconditional guarantor of TECO Finance's securities, and no subsidiaries of TECO Energy guarantee TECO Finance's securities.

(3) A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.

(4) Notes are issued and payable in either USD, BBD or East Caribbean Dollar (XCD).

(5) On acquisition of TECO Energy, Emera recorded a fair market value adjustment on the unregulated long-term debt acquired. The fair market value adjustment is amortized over the remaining term of the debt.

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		**2017**		2016
Emera – revolving credit facility (1)	June 2020	**$**	**900**	$	700
NSPI - revolving credit facility (1)	October 2021		**600**		600
Emera Maine – revolving credit facility	September 2019		**100**		107
BLPC – revolving credit facility	2018-2021		**24**		26
Total			**1,624**		1,433
Less:					
Borrowings under credit facilities			**598**		326
Letters of credit issued inside credit facilities			**44**		37
Use of available facilities			**642**		363
Available capacity under existing agreements		**$**	**982**	$	1,070

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

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, 2017**
Emera			
Syndicated credit facilities	Debt to capital ratio	Less than or equal to 0.70 to 1	0.61:1

Recent Financing Activity

Emera

On December 12, 2017, Emera exercised its accordion option under its revolving credit facility to increase the facility from $700 million to $900 million with no other change to existing terms.

TECO Energy/TECO Finance

On November 1, 2017, TECO Energy/Finance repaid a $300 million USD note upon maturity. The note was repaid using funds from existing credit facilities and cash on hand.

Emera Maine

On September 27, 2017 Emera Maine completed a 30-year $50 million USD senior unsecured notes issuance. The notes bear interest at a rate of 4.36 per cent and will mature on September 27, 2047. Proceeds were used to repay maturing notes and for general corporate purposes.

BLPC

On September 1, 2017, BLPC's interest rate on two $20 million BBD secured fixed rate senior notes maturing in 2020 and 2024 was reduced to 4.25 per cent and 5.875 per cent from 6.65 per cent and 6.875 per cent, respectively. Effective October 11, 2017, interest on their $12 million BBD demand loan facility was reduced to 4 per cent from 6.5 per cent.

Emera Brunswick Pipeline

On July 4, 2017, Emera Brunswick Pipeline amended its credit agreement to extend the maturity from February 2019 to February 2021 with no change to commercial terms from the prior agreement.

NSPI

On June 28, 2017, NSPI amended its operating credit facility to extend the maturity from October 2020 to October 2021 and the debt to capitalization ratio from 0.65:1 to 0.70:1. All other terms of the agreement are the same.

GBPC

On March 21, 2017, GBPC amended its loan agreement with the addition of two non-revolving term credit facilities. There were no significant changes in commercial terms from the prior agreement. The combined total of these new facilities is for up to $45 million USD. At December 31, 2017 the facilities were drawn in full.

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	2018	2019	2020	2021	2022	Thereafter	Total
Emera	**$** -	$ 225	$ 133	$ -	$ -	$ 2,005	$ 2,363
Emera US Finance LP	-	627	-	941	-	2,509	4,077
TECO Finance	314	-	376	-	-	-	690
Tampa Electric	319	-	-	291	282	1,518	2,410
PGS	62	-	-	59	31	176	328
NMGC	-	-	-	251	-	88	339
NMGI	-	63	-	-	-	188	251
NSPI	-	95	-	364	-	1,965	2,424
Emera Maine	6	51	37	-	113	201	408
EBP	-	-	-	248	-	-	248
GBPC	12	15	45	22	31	41	166
BLPC and ECI	28	29	55	28	11	93	244
Total	**$** 741	$ 1,105	$ 646	$ 2,204	$ 468	$ 8,784	$ 13,948

26. 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 AROs 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	**2017**	2016
Balance, January 1	**$ 170**	$ 109
Additions (1)	**2**	48
Additions due to acquisition	**-**	9
Liabilities settled	**(3)**	(2)
Accretion included in depreciation expense	**6**	7
Accretion deferred to regulatory asset (included in property, plant and equipment)	**-**	(2)
Other	**1**	1
Change in foreign exchange rate	**(4)**	-
Balance, December 31	**$ 172**	$ **170**

(1) Tampa Electric produces ash and other by-products, collectively known as CCRs, at its Big Bend and Polk power stations. The 2016 additions to ARO are to achieve compliance with the EPA's CCR rule, which contains design and operating standards for CCR management units. In 2016, the FPSC approved Tampa Electric's proposed CCR compliance program for cost recovery through the ECRC. However, additional petitions will be submitted for recovery of future project expense based on engineering studies currently being performed.

As at December 31, 2017 and 2016, some of the Company's transmission and distribution assets may have additional conditional ARO which are not recognized in the consolidated 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. AROs are included in "Other long-term liabilities" in the Consolidated Balance Sheets.

27. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2017, contractual commitments (excluding pensions and other post-retirement obligations, convertible debentures, long-term debt and AROs) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2018	2019	2020	2021	2022	Thereafter	Total
Purchased power (1)	$ 234	$ 216	$ 212	$ 209	$ 206	$ 2,148	$ 3,225
Transportation (2)	451	298	264	184	172	1,339	2,708
Fuel and gas supply	527	176	50	41	-	-	794
Capital projects	413	88	-	-	-	-	501
Long-term service agreements (3)	75	65	34	44	35	180	433
Equity investment commitments (4)	15	5	190	-	-	-	210
DSM	63	28	18	18	18	-	145
Leases and other (5)	43	12	10	7	4	61	137
	$ 1,821	$ 888	$ 778	$ 503	$ 435	$ 3,728	$ 8,153

(1) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
(2) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.
(3) 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.
(4) Emera has a commitment in connection with the Federal Loan Guarantee 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.
(5) Operating lease agreements for office space, land, plant fixtures and equipment, telecommunications services, rail cars and vehicles.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years. The UARB has approved NSPI to pay NSPML approximately $110 million and $111 million in 2018 and 2019, respectively. After 2019, the timing and amounts payable to NSPML will be subject to a regulatory filing with the UARB which will be filed no later than 2019 and closer to the timing of the Muskrat Falls project completion.

B. Legal Proceedings

Emera Florida and New Mexico

TECO Coal

TECO Coal was sold by TECO Energy on September 21, 2015 to Cambrian Coal Corporation ("Cambrian"), prior to Emera's acquisition of TECO Energy. On March 18, 2016, Cambrian delivered a notice of a purported claim to TECO Diversified. The claim asserted breach of certain representations, and fraud and willful misconduct in connection therewith, of the Securities Purchase Agreement dated September 21, 2015 by and between TECO Diversified and Cambrian related to the purchase of TECO Coal by Cambrian. While the outcome of such matter is uncertain, management does not believe its ultimate resolution will have a material adverse effect on the Company's results of operations, financial condition or cash flows.

TECO Guatemala Holdings ("TGH")

In 2013, the International Centre for the Settlement of Investment Disputes ("ICSID") Tribunal hearing the arbitration claim of TGH, a wholly owned subsidiary of TECO Energy, against the Republic of Guatemala (Guatemala) under the Dominican Republic Central America – United States Free Trade Agreement, issued an award in the case ("the Award"). The ICSID Tribunal unanimously found in favour of TGH and awarded damages to TGH of approximately $21 million USD, plus interest from October 21, 2010 at a rate equal to the U.S. prime rate plus two per cent. This award was upheld in subsequent annulment proceedings in 2016 and, in addition, TGH's application for partial annulment of the award was granted, and Guatemala was ordered to pay certain costs relating to the annulment proceedings. As a result, TGH had the right to resubmit its arbitration claim against Guatemala to seek additional damages (in addition to the previously awarded $21 million USD), as well as additional interest on the $21 million USD, and its full costs relating to the original arbitration and the new arbitration proceeding.

On September 23, 2016, TGH filed a request for resubmission to arbitration. On October 3, 2016, ICSID issued a notice of registration for TGH's request for resubmission. A new tribunal has been constituted and it issued its first procedural order. TGH's memorial was filed on September 1, 2017. Guatemala's counter-memorial was filed on February 2, 2018. In addition, TGH has sued Guatemala in Washington, D.C. court to enforce the $21 million USD due and owing. Results to date do not reflect any benefit.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and PGS divisions, is a potentially responsible party ("PRP") for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as at December 31, 2017, TEC has estimated its ultimate financial liability to be $38 million ($30 million USD), primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other long-term liabilities" on the Consolidated Balance Sheets. The environmental remediation costs associated with these sites are expected to be paid over many years.

The estimated amounts represent only the portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC's experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC's actual percentage of the remediation costs. Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings. The FPSC has approved, as part of the PGS depreciation settlement, an agreement to accelerate the amortization of the regulated asset associated with this reserve.

Emera Maine

From 2011 to 2016, four separate complaints have been filed with the FERC to challenge the ISO-New England Open Access Transmission Tariff-allowed based ROE. The first complaint, filed by a group including the Attorney General of Massachusetts, New England utilities commissions, state public advocates and end users, has been remanded to the FERC by the US Court of Appeals for further proceedings. A decision by FERC on the second and third complaints, brought by a group of consumer advocates and by a group of state commissions, state public advocates and end users respectively ("the ENE and MA AG II Cases"), is expected in 2018. The fourth complaint was filed by the Eastern Massachusetts Consumer-Owned Systems ("EMCOS"). Emera Maine has recorded a reserve of $4 million USD for the ENE and MA AG II Cases. These reserves have been recorded as "Regulatory liabilities" on the Consolidated Balance Sheets and as a reduction to "Operating revenues – regulated electric" on the Consolidated Statements of Income. The reserve was calculated based on Emera Maine's best estimate of the probable outcome. No reserve has been made in relation to the first complaint or the EMCOS complaint due to the uncertainty of the outcomes.

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. Principal Financial Risks and Uncertainties

In this section, Emera describes some of the principal financial risks management believes could materially affect the Company in the normal course of business. Risks associated with derivative instruments and fair value measurements are discussed further in note 14 and note 15.

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 to risk management.

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. Emera operates globally, with an increasing amount of the Company's adjusted net income earned outside of Canada. As such, Emera is exposed to movements in exchange rates between the Canadian dollar and, particularly, the US dollar, which could positively or adversely affect results.

Consistent with the Company's risk management policies, Emera manages currency risks through matching US denominated debt to finance its US operations and uses short-term foreign currency derivative instruments to hedge specific transactions. The Company enters into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams, capital expenditures and projects. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including foreign exchange.

The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes, or to hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries are included in AOCI.

Capital Market and Liquidity Risk

Emera's operations and projects in development require significant capital investments in property, plant and equipment. Consequently, Emera is an active participant in the debt and equity markets. Any disruption in capital markets could have a material impact on Emera's ability to fund its operations. Capital markets are global in nature and are affected by numerous events throughout the world economy. Capital market disruptions could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the company's business and regulatory framework, the ability to recover costs and earn returns, diversification, leverage, and liquidity. A change to a credit rating as a result of changes in any of these items could result in higher interest rates in future financings, increase borrowing costs under certain existing credit facilities, limit access to the commercial paper market or limit the availability of adequate credit support for subsidiary operations.

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera manages this risk by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available. Liquidity and capital needs will be financed through internally generated cash flows, short-term credit facilities, and ongoing access to capital markets. The Company reasonably expects liquidity sources to exceed ordinary course capital needs.

Interest Rate Risk

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk. Emera 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 Emera's regulated subsidiaries, the cost of debt is a component of rates and prudently incurred debt costs are recovered from customers. While regulatory ROE will generally follow the direction of interest rates, such that regulatory ROE's are likely to fall in times of reducing interest rates and rise 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 and acquisition initiatives.

Commodity Price Risk

A large portion of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. 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 and through contractual protection with counterparties, where applicable. In addition, the adoption and implementation of fuel adjustment mechanisms in its rate-regulated subsidiaries has further helped manage this risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel costs.

Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the United States and the Caribbean. Any such changes could affect the Company's future earnings, cash flows, and financial position. The value of Emera's existing deferred tax assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws. Although a reduction in the corporate income tax rate could result in lower future tax expense and tax payments, it would also reduce the value of the Company's existing deferred tax assets and could result in a charge to earnings if written down. US tax reform legislation was enacted on December 22, 2017. Although some of the specific details have yet to be clarified, this legislation has had a negative impact on the Company's 2017 financial results. Refer to the note 9 for further details. Emera monitors the status of existing tax laws to ensure that changes impacting the Company are appropriately reflected in the Company's tax compliance filings and financial results.

D. Guarantees and Letters of Credit

As at December 31, 2017, Emera had several significant guarantees and letters of credit on behalf of third parties outstanding. The following guarantees and letters of credit are not included within the Consolidated Balance Sheets as at December 31, 2017.

TECO Coal was sold on September 21, 2015 to Cambrian Coal Corporation ("Cambrian"). Pursuant to the sales agreement, Cambrian is obligated to file, in respect of each mining permit, applications in connection with the change of control with the appropriate governmental entities. As each application is approved, Cambrian is required to post a bond or other appropriate collateral in order to obtain the release of the corresponding bond secured by the TECO Energy indemnity for that permit. As at December 31, 2017, TECO Energy had remaining indemnified bonds totaling $6 million ($5 million USD).

The amounts outlined above represent the maximum theoretical amounts that TECO Energy would be required to pay to the surety companies.

The Company is working with Cambrian on the process to replace the remaining bonds. Pursuant to the securities purchase agreement, Cambrian has the obligation to indemnify and hold TECO Energy harmless from any losses incurred that arise out of the coal mining permits during the period commencing on the closing date through the date all permit approvals are obtained.

As at December 31, 2017, Emera has a standby letter of credit in the amount of $21 million for the benefit of NSP Maritime Link Inc. ("NSPML") to guarantee the performance of the obligations of the EUS-Rokstad joint venture. Rokstad Power has issued a separate letter of credit for the benefit of Emera for their portion of the work to be performed under the contract. EUS-Rokstad is a joint venture between EUS and Rokstad Power, formed for the purpose of constructing the high voltage direct current components of NSPML's transmission line. EUS and Rokstad Power are jointly and severally liable for completion of the project. Subsequent to year end, NSPML has drawn the full amount of the letter of credit, which was funded without recourse to Emera.

Emera has standby letters of credit in the amount of $28 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.

Emera Reinsurance Limited has issued a standby letter of credit to secure its obligations under reinsurance agreements. The letter of credit expires in December 2018 and is renewed annually. The amount committed as of December 31, 2017 was $6 million USD.

Emera Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under an unfunded pension plan. The letter of credit expires in June 2018 and is renewed annually. The amount committed as at December 31, 2017 was $51 million.

Collaborative Arrangements

For the years ended December 31, 2017 and 2016, the Company has identified the following material collaborative arrangements:

Through NSPI, the Company is a participant in three wind energy projects in Nova Scotia. The percentage ownership of the wind project assets is based on the relative value of each party's project assets by the total project assets. NSPI has power purchase arrangements to purchase the entire net output of the projects 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 is recorded in OM&G expenses. In 2017, NSPI recognized $18 million net expense (2016 - $18 million) in "Regulated fuel for generation and purchased power" and $3 million (2016 - $5 million) in OM&G.

28. CUMULATIVE PREFERRED STOCK

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

			December 31, 2017		December 31, 2016	
	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**	**$ 95**	3,864,636	$ 95
Series B	Floating	$ 25.00	**2,135,364**	**$ 52**	2,135,364	$ 52
Series C	$ 1.0250	$ 25.00	**10,000,000**	**$ 245**	10,000,000	$ 245
Series E	$ 1.1250	$ 26.00	**5,000,000**	**$ 122**	5,000,000	$ 122
Series F	$ 1.0625	$ 25.00	**8,000,000**	**$ 195**	8,000,000	$ 195
Total			**29,000,000**	**$ 709**	29,000,000	$ 709

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 of the Corporation in the amount determined by multiplying $25.00 by the three month Government of Canada Treasury Bill rate plus 1.84 per cent. The 2017 dividends for the Series B shares were $0.6032 per share (2016 – $0.5724).

The First Preferred Shares, Series E, are entitled to receive fixed rate cumulative cash dividends, as and when declared by the Board of Directors of the Corporation in the amount $1.1250 per share 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 up to but excluding the date fixed for redemption in the case of redemptions 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 Income 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, for only so long as the dividends remain in arrears, will be entitled to attend any meeting of shareholders of the Company at which directors are to be elected and to vote for the election of two directors out of the total number of directors elected at any such meeting.

29. NON-CONTROLLING INTEREST IN SUBSIDIARIES

Non-controlling interest in subsidiaries consisted of the following:

As at millions of Canadian dollars	**December 31 2017**	December 31 2016
ICDU	**$ 52**	$ 53
Preferred shares of GBPC	**19**	34
Domlec	**21**	25
	$ 92	$ 112

Preferred shares of GBPC:

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

	2017			2016		
Issued and outstanding:	**number of shares**		**millions of dollars**	number of shares		millions of dollars
Outstanding as at December 31	**20,000**	**$**	**19**	35,000	$	34

GBPC Non–Voting Cumulative Variable Perpetual Preferred Stock:

On December 12, 2017, GBPC redeemed 15,000 perpetual preferred shares at $1,000 Bahamian per share.

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.

30. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of Canadian dollars		Year ended December 31 **2017**		2016
Changes in non-cash working capital:				
Receivables, net	**$**	**(176)**	$	(104)
Income taxes receivable		**8**		(23)
Inventory		**31**		88
Prepayments and other current assets		**14**		(18)
Accounts payable		**3**		162
Income taxes payable		**(17)**		14
Other current liabilities		**33**		15
Total non-cash working capital	**$**	**(104)**	$	134
Supplemental disclosure of cash paid:				
Interest	**$**	**689**	$	480
Income taxes	**$**	**63**	**$**	57
Supplemental disclosure of non-cash activities:				
Common share dividends reinvested	**$**	**166**	$	103
Beneficial Conversion Feature of the convertible debentures	**$**	**-**	$	43

31. STOCK-BASED COMPENSATION

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

Eligible 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 10 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. This 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 dividend.

Compensation cost for shares issued by Emera for the year ended December 31, 2017 under the Employee Common Share Purchase Plan was $1 million (2016 – $1 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,		**2017**		2016
Weighted average fair value per option	**$**	**2.37**	$	2.80
Expected term		**5 years**		5 years
Risk-free interest rate		**1.22 %**		0.66 %
Expected dividend yield		**4.60 %**		4.08 %
Expected volatility		**14.41 %**		15.45 %

The following table summarizes information related to the stock options for 2017:

	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, 2016	2,920,000	$	37.42	1,520,125	$	2.69
Granted	827,400		45.16	827,400		2.37
Exercised	(103,825)		28.91	N/A		N/A
Forfeited	-		-	(607,875)		2.73
Options outstanding December 31, 2017	**3,643,575**	**$**	**39.42**	**1,739,650**	**$**	**2.52**
Options exercisable December 31, 2017 (2)(3)	**1,903,925**	**$**	**35.37**			

(1) As at December 31, 2017 there was $3 million of unrecognized compensation related to stock options not yet vested which is expected to be recognized over a weighted average period of approximately 2.5 years (2016 - $3 million, 2.4 years).
(2) As at December 31, 2017, the weighted average remaining term of vested options was 5.4 years with an aggregate intrinsic value of $22 million (2016 - 5.7 years, $17 million).
(3) As at December 31, 2017 the fair value of options that vested in the year was $2 million (2016 - $2 million).

Compensation cost recognized for stock options for the year ended December 31, 2017 was $2 million (2016 – $2 million), which is included in "Operating, maintenance and general" on the Consolidated Statements of Income.

As at December 31, 2017, cash received from option exercises was $3 million (2016 – $16 million). The total intrinsic value of options exercised for the year ended December 31, 2017 was $2 million (2016 – $13 million). The range of exercise prices for the options outstanding as at December 31, 2017 was $21.58 to $46.19 (2016 – $20.42 to $46.19).

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, 2017 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, 2016	680,931	$ 27.50	395,798	$ 33.88
Granted including DRIP	73,185	37.74	86,281	42.96
Exercised	(2,482)	46.58	(9,486)	44.00
Forfeited	(34)	46.58	(108)	45.39
Outstanding and exercisable as at December 31, 2017	**751,600**	**$ 28.44**	**472,485**	**$ 35.33**

Compensation cost recognized for employee and director DSU for the year ended December 31, 2017 was $7 million (2016 – $8 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2017 were $2 million (2016 – $3 million).

Performance Share Unit Plan

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

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

A summary of the activity related to employee PSUs for the year ended December 31, 2017 is presented in the following table:

	Employee PSU		Weighted Average Grant Date Fair Value		Aggregate intrinsic value
Outstanding as at December 31, 2016	560,880	$	37.55	$	25.5
Granted including DRIP	519,789		44.35		
Exercised	(220,075)		30.67		
Forfeited	(30,596)		43.66		
Outstanding as at December 31, 2017	**829,998**	**$**	**43.41**	**$**	**41.1**

Compensation cost recognized for the PSU plan for the year ended December 31, 2017 was $14 million (2016 – $11 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2017 were $4 million (2016 – $4 million).

32. VARIABLE INTEREST ENTITIES

The Company performs ongoing analysis to assess whether it holds any Variable Interest Entities ("VIE"). 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, 2017 and 2016, the Company has identified the following material VIEs:

Emera holds a variable interest in NSPML, a VIE for which it was determined that Emera is not the primary beneficiary since it does not have the controlling financial interest of NSPML. In Q2 2014, when the critical milestones were achieved, 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.

BLPC 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. Emera's consolidated VIE in the SIF is recorded as an "Investment securities", "Restricted cash" and "Regulatory liabilities" on the Consolidated Balance Sheets. Amounts included in restricted cash represent the cash portion of funds required to be set aside for the BLPC SIF.

The Company has identified certain long-term purchase power agreements that meet the definition of 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.

The following table provides information about Emera's portion of material unconsolidated VIEs:

As at	**December 31, 2017**		December 31, 2016	
millions of Canadian dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 510**	**$ 67**	$ 315	$ 577

33. 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.

34. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 9, 2018, the date the financial statements were issued.

35. SUPPLEMENTAL FINANCIAL INFORMATION

On June 16, 2016, Emera US Finance LP, (in such capacity, the "Issuer"), issued $3.25 billion USD senior unsecured notes ("U.S. Notes"). The U.S Notes are fully and unconditionally guaranteed, on a joint and several basis, by Emera (in such capacity, the "Parent Company") and EUSHI (in such capacity, the "Guarantor Subsidiaries"). Emera owns, directly or indirectly, all of the limited and general partnership interests in Emera US Finance LP.

The following condensed consolidated financial statements present the results of operations, financial position and cash flows of the Parent Company, Subsidiary Issuer, Guarantor Subsidiaries and all other Non-guarantor Subsidiaries independently and on a consolidated basis.

Our guarantors were not determined using geographic, service line or other similar criteria, and as a result, the "Parent", "Subsidiary Issuer", "Guarantor Subsidiaries" and "Non-guarantor Subsidiaries" columns each include portions of our domestic and international operations. Accordingly, this basis of presentation is not intended to present our financial condition, results of operations or cash flows for any purpose other than to comply with the specific requirements for guarantor reporting.

Emera Incorporated
Condensed Consolidated Statements of Income
For the year ended December 31, 2017

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Operating revenues	$ -	$ -	$ 4,165	$ 2,118	$ (57)	**$ 6,226**
Operating expenses	41	-	3,241	1,610	(57)	**4,835**
Income (loss) from operations	(41)	-	924	508	-	**1,391**
Income (loss) from equity investments in subsidiaries	336	-	-	-	(336)	**-**
Income from equity investments	1	-	1	122	-	**124**
Intercompany income (expenses), net	92	195	(204)	(45)	(38)	**-**
Other income (expenses), net	-	-	16	(19)	5	**2**
Interest expense, net	138	155	242	163	-	**698**
Income (loss) before provision for income taxes	250	40	495	403	(369)	**819**
Income tax expense (recovery)	(44)	17	511	36	-	**520**
Net income (loss)	294	23	(16)	367	(369)	**299**
Non-controlling interest in subsidiaries	-	-	-	1	4	**5**
Preferred stock dividends	28	-	29	13	(42)	**28**
Net income (loss) attributable to common shareholders	$ 266	$ 23	$ (45)	$ 353	$ (331)	**$ 266**
Comprehensive income (loss) of Emera Incorporated	$ -	$ 3	$ (392)	$ 372	$ 17	**$ -**

Emera Incorporated
Condensed Consolidated Statements of Income
For the year ended December 31, 2016

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Operating revenues	$ -	$ -	$ 2,494	$ 1,818	$ (35)	**$ 4,277**
Operating expenses	39	-	2,127	1,591	(35)	**3,722**
Income (loss) from operations	(39)	-	367	227	-	**555**
Income (loss) from equity investments in subsidiaries	150	-	-	-	(150)	**-**
Income from equity investments	18	-	-	82	-	**100**
Intercompany income (expenses), net	203	101	(107)	(151)	(46)	**-**
Other income (expenses), net	135	-	24	15	-	**174**
Interest expense, net	226	85	127	147	-	**585**
Income (loss) before provision for income taxes	241	16	157	26	(196)	**244**
Income tax expense (recovery)	(14)	7	48	(63)	-	**(22)**
Net income (loss)	255	9	109	89	(196)	**266**
Non-controlling interest in subsidiaries	-	-	-	7	4	**11**
Preferred stock dividends	28	-	31	19	(50)	**28**
Net income (loss) attributable to common shareholders	$ 227	$ 9	$ 78	$ 63	$ (150)	**$ 227**
Comprehensive income (loss) of Emera Incorporated	$ 228	$ 19	$ 205	$ 59	$ (283)	**$ 228**

Emera Incorporated
Condensed Consolidated Balance Sheets
As at December 31, 2017

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Assets						
Current assets						
Cash and cash equivalents	$ 276	$ 21	$ 47	$ 94	$ -	**$ 438**
Restricted cash	-	-	1	64	-	**65**
Inventory	-	-	243	175	-	**418**
Derivative instruments	5	-	11	131	(6)	**141**
Regulatory assets	-	-	114	24	-	**138**
Intercompany receivables	74	9	4	108	(195)	**-**
Receivables and other current assets	3	-	546	777	-	**1,326**
Total current assets	358	30	966	1,373	(201)	**2,526**
Property, plant and equipment, net of accumulated depreciation	17	-	12,258	4,720	-	**16,995**
Other assets						
Deferred income taxes	70	-	(10)	71	7	**138**
Derivative instruments	4	-	2	110	(4)	**112**
Regulatory assets	-	-	552	686	-	**1,238**
Net investment in direct financing lease	-	-	12	469	-	**481**
Investments in subsidiaries accounted for using the equity method	8,490	-	-	-	(8,490)	**-**
Investments subject to significant influence	5	-	13	1,197	-	**1,215**
Goodwill	-	-	5,709	96	-	**5,805**
Intercompany notes receivable	1,140	4,285	1	955	(6,381)	**-**
Other investments - intercompany	-	-	-	70	(70)	**-**
Other long-term assets	29	-	68	184	(20)	**261**
Total other assets	9,738	4,285	6,347	3,838	(14,958)	**9,250**
Total assets	$ 10,113	$ 4,315	$ 19,571	$ 9,931	$ (15,159)	**$ 28,771**

Emera Incorporated
Condensed Consolidated Balance Sheets – Continued
As at December 31, 2017

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Liabilities and Equity						
Current liabilities						
Short-term debt	$ -	$ -	$ 1,241	$ -	$ -	**$ 1,241**
Current portion of long-term debt	-	-	701	40	-	**741**
Accounts payable	9	-	620	532	-	**1,161**
Intercompany payable	55	6	90	74	(225)	**-**
Derivative instruments	5	-	52	175	(5)	**227**
Regulatory liabilities	-	-	91	136	(1)	**226**
Other current liabilities	60	6	137	147	-	**350**
Total current liabilities	129	12	2,932	1,104	(231)	**3,946**
Long-term liabilities						
Long-term debt	2,205	4,034	3,741	3,160	-	**13,140**
Intercompany long-term debt	656	-	4,582	1,139	(6,377)	**-**
Deferred income taxes	-	4	435	565	7	**1,011**
Derivative instruments	4	-	4	79	(4)	**83**
Regulatory liabilities	-	-	1,889	353	-	**2,242**
Pension and post-retirement liabilities	21	-	341	197	-	**559**
Other long-term liabilities	9	-	267	352	(19)	**609**
Total long-term liabilities	2,895	4,038	11,259	5,845	(6,393)	**17,644**
Equity						
Common stock	5,601	242	4,311	2,136	(6,689)	**5,601**
Cumulative preferred stock	709	-	620	76	(696)	**709**
Contributed surplus	76	-	110	148	(258)	**76**
Accumulated other comprehensive income (loss)	(188)	(9)	(36)	(185)	230	**(188)**
Retained earnings	891	32	375	735	(1,142)	**891**
Total Emera Incorporated equity	7,089	265	5,380	2,910	(8,555)	**7,089**
Non-controlling interest in subsidiaries	-	-	-	72	20	**92**
Total equity	7,089	265	5,380	2,982	(8,535)	**7,181**
Total liabilities and equity	$ 10,113	$ 4,315	$ 19,571	$ 9,931	$ (15,159)	**$ 28,771**

Emera Incorporated
Condensed Consolidated Balance Sheets
As at December 31, 2016

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Assets						
Current assets						
Cash and cash equivalents	$ 200	$ 28	$ 48	$ 128	$ -	**$ 404**
Restricted cash	-	-	1	86	-	**87**
Inventory	-	-	273	199	-	**472**
Derivative instruments	13	-	33	112	(13)	**145**
Regulatory assets	-	-	54	26	-	**80**
Intercompany receivable	57	9	11	569	(646)	**-**
Prepayments and other current assets	3	-	478	842	-	**1,323**
Total current assets	273	37	898	1,962	(659)	**2,511**
Property, plant and equipment, net of accumulated depreciation	14	-	12,724	4,552	-	**17,290**
Other assets						
Deferred income taxes	31	-	18	114	(38)	**125**
Derivative instruments	12	-	2	129	(12)	**131**
Regulatory assets	-	-	647	595	-	**1,242**
Net investment in direct financing lease	-	-	13	475	-	**488**
Investments in subsidiaries accounted for using the equity method	8,349	-	-	-	(8,349)	**-**
Investments subject to significant influence	5	-	13	929	-	**947**
Goodwill	-	-	6,110	103	-	**6,213**
Intercompany notes receivable	1,341	4,558	16	589	(6,504)	**-**
Other investments - intercompany	-	-	-	2,270	(2,270)	**-**
Other long-term assets	33	-	85	175	(19)	**274**
Total other assets	9,771	4,558	6,904	5,379	(17,192)	**9,420**
Total assets	$ 10,058	$ 4,595	$ 20,526	$ 11,893	$ (17,851)	**$ 29,221**

Emera Incorporated
Condensed Consolidated Balance Sheets – Continued
As at December 31, 2016

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Liabilities and Equity						
Current liabilities						
Short-term debt	$ -	$ -	$ 948	$ 13	$ -	**$ 961**
Current portion of long-term debt	-	-	436	40	-	**476**
Accounts payable	6	-	756	480	-	**1,242**
Intercompany payable	534	6	81	25	(646)	**-**
Derivative instruments	14	-	10	314	(13)	**325**
Regulatory liabilities	-	-	225	137	-	**362**
Other current liabilities	54	13	130	161	-	**358**
Total current liabilities	608	19	2,586	1,170	(659)	**3,724**
Long-term liabilities						
Long-term debt	2,338	4,314	4,687	2,929	-	**14,268**
Intercompany long-term debt	366	-	4,778	1,357	(6,501)	**-**
Deferred income taxes	-	1	1,193	516	(38)	**1,672**
Derivative instruments	12	-	-	150	(12)	**150**
Regulatory liabilities	-	-	973	304	-	**1,277**
Pension and post-retirement liabilities	17	-	433	219	-	**669**
Other long-term liabilities	13	-	274	377	(19)	**645**
Total long-term liabilities	2,746	4,315	12,338	5,852	(6,570)	**18,681**
Equity						
Common stock	4,738	242	4,177	3,997	(8,416)	**4,738**
Cumulative preferred stock	709	-	620	271	(891)	**709**
Contributed surplus	75	-	45	106	(151)	**75**
Accumulated other comprehensive income (loss)	106	10	340	(191)	(159)	**106**
Retained earnings	1,076	9	420	610	(1,039)	**1,076**
Total Emera Incorporated equity	6,704	261	5,602	4,793	(10,656)	**6,704**
Non-controlling interest in subsidiaries	-	-	-	78	34	**112**
Total equity	6,704	261	5,602	4,871	(10,622)	**6,816**
Total liabilities and equity	$ 10,058	$ 4,595	$ 20,526	$ 11,893	$ (17,851)	**$ 29,221**

Emera Incorporated
Condensed Consolidated Statements of Cash Flows
For the year ended December 31, 2017

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Net cash provided by (used in) by operating activities	$ 195	$ 22	$ 712	$ 1,125	$ (861)	**$ 1,193**
Investing activities						
Additions to property, plant and equipment	(5)	-	(1,031)	(480)	(13)	**(1,529)**
Net purchase of investments subject to significant influence, inclusive of acquisition costs	-	-	-	(213)	-	**(213)**
Other intercompany investing activities	(708)	(26)	15	1,818	(1,099)	**-**
Other investing activities	(34)	-	(20)	32	3	**(19)**
Net cash provided by (used in) investing activities	(747)	(26)	(1,036)	1,157	(1,109)	**(1,761)**
Financing activities						
Change in short-term debt, net	-	-	365	(13)	-	**352**
Proceeds from long-term debt, net of issuance costs	-	-	147	(131)	113	**129**
Retirement of long-term debt	-	-	(413)	(55)	15	**(453)**
Net borrowings (repayments) under committed credit facilities	(30)	-	21	233	6	**230**
Issuance of common stock, net of issuance costs	682	-	134	(1,837)	1,703	**682**
Issuance of preferred stock, net of issuance costs	-	-	-	(195)	195	**-**
Dividends on common stock	(287)	-	-	(272)	272	**(287)**
Dividends on preferred stock	(28)	-	(29)	(13)	42	**(28)**
Dividends paid by subsidiaries to non-controlling interest	-	-	-	(2)	(4)	**(6)**
Other financing activities	290	-	96	(40)	(372)	**(26)**
Net cash provided by (used in) financing activities	627	-	321	(2,325)	1,970	**593**
Effect of exchange rate changes on cash and cash equivalents	1	(3)	2	(13)	-	**(13)**
Net increase (decrease) in cash and cash equivalents	76	(7)	(1)	(56)	-	**12**
Cash, cash equivalents and restricted cash, beginning of year	200	28	49	214	-	**491**
Cash, cash equivalents and restricted cash, end of year	$ 276	$ 21	$ 48	$ 158	$ -	**$ 503**

Emera Incorporated
Condensed Consolidated Statements of Cash Flows
For the year ended December 31, 2016

millions of Canadian dollars	Parent	Subsidiary Issuer	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	**Consolidated**
Net cash provided by (used in) operating activities	$ 265	$ 29	$ 481	$ 107	$ 171	**$ 1,053**
Investing activities						
Acquisitions, net of cash acquired	-	-	(8,409)	-	-	**(8,409)**
Additions to property, plant and equipment	(2)	-	(673)	(405)	-	**(1,080)**
Net purchase of investments subject to significant influence, inclusive of acquisition costs	-	-	-	(276)	-	**(276)**
Net proceeds on sale of investment subject to significant influence and held-for-trading common shares	665	-	-	-	-	**665**
Other intercompany investing activities	(2,348)	(4,416)	(18)	(2,397)	9,179	**-**
Other investing activities	-	-	(3)	66	-	**63**
Net cash provided by (used in) investing activities	(1,685)	(4,416)	(9,103)	(3,012)	9,179	**(9,037)**
Financing activities						
Change in short-term debt, net	(14)	-	122	(4)	14	**118**
Proceeds from long-term debt, net of issuance costs	2,037	4,187	4,516	764	(5,081)	**6,423**
Proceeds from convertible debentures represented by instalment receipts, net of issuance costs	(44)	-	-	1,457	-	**1,413**
Retirement of long-term debt	(250)	-	(6)	(36)	19	**(273)**
Net borrowings (repayments) under committed credit facilities	(210)	-	-	(99)	(6)	**(315)**
Issuance of common stock, net of issuance costs	354	242	3,865	95	(4,202)	**354**
Issuance of preferred stock, net of issuance costs	-	-	195	-	(195)	**-**
Dividends on common stock	(221)	-	-	(254)	254	**(221)**
Dividends on preferred stock	(28)	-	(31)	(18)	49	**(28)**
Dividends paid by subsidiaries to non-controlling interest	-	-	-	(2)	(3)	**(5)**
Other financing activities	-	-	(18)	185	(185)	**(18)**
Net cash provided by (used in) financing activities	1,624	4,429	8,643	2,088	(9,336)	**7,448**
Effect of exchange rate changes on cash and cash equivalents	(4)	(14)	7	(54)	-	**(65)**
Net increase (decrease) in cash and cash equivalents	200	28	28	(871)	14	**(601)**
Cash, cash equivalents and restricted cash, beginning of year	-	-	21	1,085	(14)	**1,092**
Cash, cash equivalents and restricted cash, end of year	$ 200	$ 28	$ 49	$ 214	$ -	**$ 491**