EMERA INCORPORATED

Unaudited Condensed Consolidated

Interim Financial Statements

September 30, 2017 and 2016

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Operating revenues				
Regulated electric	**$ 1,214**	$ 1,246	**$ 3,593**	$ 2,301
Regulated gas	**187**	192	**727**	217
Non-regulated	**26**	(51)	**433**	246
Total operating revenues	**1,427**	1,387	**4,753**	2,764
Operating expenses				
Regulated fuel for generation and purchased power	**396**	456	**1,182**	810
Regulated cost of natural gas	**71**	69	**272**	69
Regulated fuel adjustment mechanism and fixed cost deferrals	**13**	6	**43**	48
Non-regulated fuel for generation and purchased power	**40**	64	**149**	243
Non-regulated direct costs	**6**	4	**26**	7
Operating, maintenance and general	**329**	423	**1,035**	746
Provincial, state and municipal taxes	**82**	85	**247**	118
Depreciation and amortization	**207**	204	**644**	376
Total operating expenses	**1,144**	1,311	**3,598**	2,417
Income from operations	**283**	76	**1,155**	347
Income from equity investments (note 5)	**34**	23	**90**	79
Other income (expenses), net (note 6)	**(3)**	14	**-**	169
Interest expense, net (note 7)	**170**	233	**523**	416
Income (loss) before provision for income taxes	**144**	(120)	**722**	179
Income tax expense (recovery)(note 8)	**45**	(44)	**191**	(16)
Net income (loss)	**99**	(76)	**531**	195
Non-controlling interest in subsidiaries	**4**	5	**9**	10
Net income (loss) of Emera Incorporated	**95**	(81)	**522**	185
Preferred stock dividends	**14**	14	**28**	28
Net income (loss) attributable to common shareholders	**$ 81**	$ (95)	**$ 494**	$ 157
Weighted average shares of common stock outstanding (in millions) (note 10)				
Basic	**213.8**	182.8	**212.7**	160.5
Diluted	**215.3**	182.8	**214.1**	162.0
Earnings per common share (note 10)				
Basic	**$ 0.38**	$ (0.52)	**$ 2.32**	$ 0.98
Diluted	**$ 0.38**	$ (0.52)	**$ 2.31**	$ 0.97
Dividends per common share declared	**$ 1.0875**	$ 1.0450	**$ 2.1325**	$ 1.9950

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

Emera Incorporated
Condensed Consolidated Statements of Comprehensive Income (Unaudited)

For the millions of Canadian dollars		Three months ended September 30		Nine months ended September 30
	2017	2016	**2017**	2016
Net income	**$ 99**	$ (76)	**$ 531**	$ 195
Other comprehensive income (loss), net of tax				
Foreign currency translation adjustment (1)	**(263)**	58	**(495)**	(121)
Unrealized gains (losses) on net investment hedges (2) (3)	**51**	(13)	**103**	(13)
Cash flow hedges				
Net derivative gains (losses) (4)	**6**	(3)	**11**	14
Less: reclassification adjustment for losses (gains) included in income (5)	**1**	3	**5**	7
Net effects of cash flow hedges	**7**	-	**16**	21
Unrealized gains (losses) on available-for-sale investment				
Unrealized gain (loss) arising during the period	**3**	3	**7**	3
Less: reclassification adjustment for (gains) losses recognized in income	**(1)**	(4)	**(2)**	(4)
Net unrealized holding gains (losses)	**2**	(1)	**5**	(1)
Net change in unrecognized pension and post-retirement benefit obligation (6)	**8**	12	**21**	29
Other equity method reclassification adjustment (7)	**-**	-	**-**	(46)
Other comprehensive income (loss) (8)	**(195)**	56	**(350)**	(131)
Comprehensive income (loss)	**(96)**	(20)	**181**	64
Comprehensive income (loss) attributable to non-controlling interest	**1**	6	**3**	5
Comprehensive income (loss) of Emera Incorporated	**$ (97)**	$ (26)	**$ 178**	$ 59

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1) Net of tax recovery of nil (2016 - nil tax recovery) for the three months ended September 30, 2017 and tax recovery of nil (2016 – $3 million tax recovery) for the nine months ended September 30, 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 tax expense) for the three months ended September 30, 2017 and tax expense of $10 million (2016 – nil tax expense) for the nine months ended September 30, 2017.
4) Net of tax expense of nil (2016 - $2 million tax expense) for the three months ended September 30, 2017 and tax expense of nil (2016 - $3 million tax expense) for the nine months ended September 30, 2017.
5) Net of tax recovery of nil (2016 - $1 million tax expense) for the three months ended September 30, 2017 and tax expense of $1 million (2016 – nil tax expense) for the nine months ended September 30, 2017.
6) Net of tax recovery of nil (2016 - $2 million tax recovery) for the three months ended September 30, 2017 and tax expense of $2 million (2016 – $2 million tax recovery) for the nine months ended September 30, 2017.
7) Net of tax recovery of nil (2016 - nil tax recovery) for the three months ended September 30, 2017 and tax recovery of nil (2016 – $9 million tax recovery) for the nine months ended September 30, 2017.
8) Net of tax expense of $9 million (2016 - $1 million tax expense) for the three months ended September 30, 2017 and tax expense of $13 million (2016 – $11 million tax recovery) for the nine months ended September 30, 2017.

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at millions of Canadian dollars	**September 30 2017**	December 31 2016
Assets		
Current assets		
Cash and cash equivalents	**$ 221**	$ 404
Restricted cash	**79**	87
Receivables, net	**896**	1,014
Income taxes receivable	**15**	33
Inventory	**452**	472
Derivative instruments (notes 12 and 13)	**128**	145
Regulatory assets (note 14)	**90**	80
Prepayments and other current assets	**147**	276
Total current assets	**2,028**	2,511
Property, plant and equipment, net of accumulated depreciation and amortization of $7,785 and $7,787, respectively	**16,692**	17,290
Other assets		
Income taxes receivable	**48**	48
Deferred income taxes	**111**	125
Derivative instruments (notes 12 and 13)	**101**	131
Pension and post-retirement assets (note 16)	**8**	9
Regulatory assets (note 14)	**1,257**	1,242
Net investment in direct financing lease	**483**	488
Investments subject to significant influence (note 5)	**1,167**	947
Investment securities	**55**	48
Goodwill	**5,775**	6,213
Other long-term assets	**157**	169
Total other assets	**9,162**	9,420
Total assets	**$ 27,882**	$ 29,221

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

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited) – Continued

As at millions of Canadian dollars	**September 30 2017**	December 31 2016
Liabilities and Equity		
Current liabilities		
Short-term debt (note 17)	**$ 939**	$ 961
Current portion of long-term debt	**1,105**	476
Accounts payable	**1,070**	1,242
Income taxes payable	**4**	19
Derivative instruments (notes 12 and 13)	**145**	325
Regulatory liabilities (note 14)	**200**	362
Pension and post-retirement liabilities (note 16)	**24**	58
Other current liabilities	**493**	281
Total current liabilities	**3,980**	3,724
Long-term liabilities		
Long-term debt (note 18)	**13,056**	14,268
Deferred income taxes	**1,776**	1,672
Convertible debentures	**3**	8
Derivative instruments (notes 12 and 13)	**83**	150
Regulatory liabilities (note 14)	**1,132**	1,277
Asset retirement obligations	**167**	170
Pension and post-retirement liabilities (note 16)	**590**	669
Other long-term liabilities	**444**	467
Total long-term liabilities	**17,251**	18,681
Commitments and contingencies (note 19)		
Equity		
Common stock (note 9)	**4,875**	4,738
Cumulative preferred stock	**709**	709
Contributed surplus	**76**	75
Accumulated other comprehensive income (loss) (note 11)	**(238)**	106
Retained earnings	**1,120**	1,076
Total Emera Incorporated equity	**6,542**	6,704
Non-controlling interest in subsidiaries	**109**	112
Total equity	**6,651**	6,816
Total liabilities and equity	**$ 27,882**	$ 29,221

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

Approved on behalf of the Board of Directors

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

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

Emera Incorporated
Condensed Consolidated Statements of Cash Flows (Unaudited)

For the millions of Canadian dollars	Nine months ended September 30 **2017**	2016
Operating activities		
Net income	**$ 531**	$ 195
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**637**	383
Income from equity investments, net of dividends	**(66)**	(49)
Allowance for equity funds used during construction	**(7)**	(12)
Deferred income taxes, net	**143**	(51)
Net change in pension and post-retirement liabilities	**(23)**	(3)
Regulated fuel adjustment mechanism and fixed cost deferrals	**49**	49
Net change in fair value of derivative instruments	**(259)**	56
Net change in regulatory assets and liabilities	**(169)**	7
Net change in capitalized transportation capacity	**110**	184
Foreign exchange loss (gain)	**(1)**	47
Gain on APUC sale of common shares and conversion of subscription receipts	**-**	(235)
Other operating activities, net	**11**	44
Changes in non-cash working capital (note 20)	**85**	252
Net cash provided by operating activities	**1,041**	867
Investing activities		
Acquisition, net of cash acquired (note 3)	**-**	(8,409)
Additions to property, plant and equipment	**(1,084)**	(617)
Net purchase of investments subject to significant influence, inclusive of acquisition costs	**(183)**	(171)
Net proceeds on sale of investment subject to significant influence	**-**	525
Other investing activities	**(4)**	65
Net cash used in investing activities	**(1,271)**	(8,607)
Financing activities		
Change in short-term debt, net	**51**	(24)
Proceeds from long-term debt, net of issuance costs	**39**	6,228
Proceeds from convertible debentures, net of issuance costs	**-**	1,414
Retirement of long-term debt	**(48)**	(18)
Net borrowings (repayments) under committed credit facilities	**253**	(233)
Issuance of common stock, net of issuance costs	**7**	20
Dividends on common stock	**(208)**	(155)
Dividends on preferred stock	**(21)**	(21)
Dividends paid by subsidiaries to non-controlling interest	**(5)**	(5)
Other financing activities	**(6)**	(49)
Net cash provided by financing activities	**62**	7,157
Effect of exchange rate changes on cash and cash equivalents	**(15)**	(75)
Net decrease in cash and cash equivalents	**(183)**	(658)
Cash and cash equivalents, beginning of period	**404**	1,073
Cash and cash equivalents, end of period	**$ 221**	**$** 415
Cash and cash equivalents consists of:		
Cash	**$ 220**	**$** 353
Short-term investments	**1**	62
Cash and cash equivalents	**$ 221**	**$** 415

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

Emera Incorporated
Condensed Consolidated Statements of Changes in Equity (Unaudited)

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss) ("AOCI")	Retained Earnings	Emera Total Equity	Non-Controlling Interest	Total Equity
For the nine months ended September 30, 2017								
Balance, December 31, 2016	$ 4,738	$ 709	$ 75	$ 106	$ 1,076	$ 6,704	$ 112	$ 6,816
Net income of Emera Incorporated	-	-	-	-	522	522	9	531
Other comprehensive income (loss), net of tax expense of $13 million	-	-	-	(344)	-	(344)	(6)	(350)
Issuance of common stock, net of after-tax issuance costs	6	-	-	-	-	6	-	6
Dividends declared on preferred stock (Series A: $0.63880 /share, Series B: $0.60320/share, Series C: $1.02500/share, Series E: $1.12500/share and Series F: $1.06250/share)	-	-	-	-	(28)	(28)	-	(28)
Dividends declared on common stock ($2.1325/share)	-	-	-	-	(451)	(451)	-	(451)
Common stock issued under purchase plan	128	-	-	-	-	128	-	128
Stock-based compensation	2	-	1	-	-	3	-	3
Other	1	-	-	-	1	2	(6)	(4)
Balance, September 30, 2017	$ 4,875	$ 709	$ 76	$ (238)	$ 1,120	$ 6,542	$ 109	$ 6,651

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

Emera Incorporated
Condensed Consolidated Statements of Changes in Equity (Unaudited) – Continued

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income ("AOCI")	Retained Earnings	Emera Total Equity	Non-Controlling Interest	Total Equity
For the nine months ended September 30, 2016								
Balance, December 31, 2015	$ 2,157	$ 709	$ 29	$ 137	$ 1,168	$ 4,200	$ 134	$ 4,334
Net income of Emera Incorporated	-	-	-	-	185	185	10	195
Other comprehensive income (loss), net of tax recovery of $11 million	-	-	-	(127)	-	(127)	(5)	(132)
Issuance of common stock, net of after-tax issuance costs	2,112	-	-	-	-	2,112	-	2,112
Dividends declared on preferred stock (Series A: $0.47910/share, Series B: $0.28180/share, Series C: $0.65740/share, Series E: $0.81875/share and Series F: $0.81250/share)	-	-	-	-	(28)	(28)	-	(28)
Dividends declared on common stock ($1.9950/share)	-	-	-	-	(324)	(324)	-	(324)
Common stock issued under purchase plan	69	-	-	-	-	69	-	69
Stock-based compensation	17	-	-	-	-	17	-	17
Beneficial conversion feature, net of tax	-		43			43		43
Acquisition of non-controlling interest of ECI	3	-	7	-	-	10	(24)	(14)
Other	-	-	(4)	(4)	5	(3)	(5)	(8)
Balance, September 30, 2016	$ 4,358	$ 709	$ 75	$ 6	$ 1,006	$ 6,154	$ 110	$ 6,264

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

Emera Incorporated
Notes to the Condensed Consolidated Interim Financial Statements (Unaudited)
As at September 30, 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, gas transmission and distribution and utility energy services.

Emera's primary rate-regulated subsidiaries and investments at September 30, 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 745,000 customers in West Central Florida and Peoples Gas System Division, ("PGS") a regulated gas distribution utility, serving approximately 374,000 customers across Florida;
    - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 521,000 customers across New Mexico;
    - 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 513,000 customers;
- Emera Maine, an electric transmission and distribution utility, serving approximately 159,000 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 ICD Utilities Limited approved Emera's acquisition of their common shares for total consideration of approximately $35 million USD. Completion of this transaction is anticipated in Q4 2017, at which time Emera's interest in GBPC will increase from 80.4 per cent 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. See note 14 for additional information;
    - 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 is developing 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 is scheduled to be completed in Q4 2017 and to be in service in January 2018;
    - a 53.7 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. 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. 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" ("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;
    - 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 unaudited condensed consolidated interim financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP"). The significant accounting policies applied to these unaudited condensed consolidated interim financial statements are consistent with those disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2016.

In the opinion of management, these unaudited condensed consolidated interim financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera. Financial results for this interim period are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2017.

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

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.

Seasonal Nature of Operations

Interim results are not necessarily indicative of results for the full year, primarily due to seasonal factors. Electricity and gas sales and related transmission and distribution, vary over the year. The first quarter is typically the strongest period, reflecting colder weather and fewer daylight hours in the winter season in northeastern North America, where historically a substantial portion of Emera's electricity business is located. However, with the addition of Emera Florida and New Mexico, the third quarter will provide stronger earnings for Emera than prior to the acquisition due to the summer being the peak electricity season in Florida. Certain quarters may also be impacted by weather and the number and severity of storms.

2. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all Accounting Standard Updates ("ASU") issued by the Financial Accounting Standards Board (the "FASB"). The ASUs that have been issued, but that are not yet effective, are consistent with those disclosed in the 2016 audited consolidated financial statements, with the exception of the items noted below.

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 has 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 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 Q3 2017, the Company implemented a project plan and is in the process of evaluating the impact of adoption of this standard on its financial statements and disclosures. 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.

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. The Company is currently evaluating the impact of the adoption of this standard on the consolidated financial statements, including the eligibility for capitalization of the other components of net benefit cost given the application of ASC 980 *Regulated Operations*. 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 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.

3. 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"), Florida Public Service Commission ("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.

Acquisition Related Expenses
There were no acquisition related expenses incurred for the three and nine months ended September 30, 2017. Acquisition related expenses totalled $156 million ($119 million after tax) and $249 million ($179 million after tax) for the three and nine months ended September 30, 2016. These acquisition related expenses were included in Interest expense, net and Operating, maintenance and general on the Condensed 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 made to the pro forma net income attributable to common shareholders were $119 million and $66 million, respectively, for the three and nine months ended September 30, 2016.

For the millions of Canadian dollars	Three months ended September 30	Nine months ended September 30
	2016	2016
Pro forma operating revenues	$ 1,397	$ 4,521
Pro forma net income attributable to common shareholders	$ 24	$ 329

4. 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.

As at September 30, 2017, Emera has six reportable segments, specifically:

- 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(3)	NSPI	Emera Maine	Emera Caribbean	Emera Energy	Corporate and Other	Inter-Segment Eliminations	Total
For the three months ended September 30, 2017								
Operating revenues from external customers (1)	$ 926 $	283 $	74 $	109 $	13 $	21 $	- $	1,426
Inter-segment revenues (1)	-	-	-	-	3	14	(16)	1
Total operating revenues	926	283	74	109	16	35	(16)	1,427
Net income (loss) attributable to common shareholders (2)	120	7	13	12	(39)	(32)	-	81
For the nine months ended September 30, 2017								
Operating revenues from external customers (1)	2,760	981	226	327	393	67	-	4,754
Inter-segment revenues (1)	-	2	-	-	10	28	(41)	(1)
Total operating revenues	2,760	983	226	327	403	95	(41)	4,753
Net income (loss) attributable to common shareholders (2)	302	106	38	30	103	(85)	-	494
For the three months ended September 30, 2016								
Operating revenues from external customers (1)	959 $	291 $	77 $	115 $	(61) $	6 $	- $	1,387
Inter-segment revenues (1)	-	1	-	-	3	6	(10)	-
Total operating revenues	959	292	77	115	(58)	12	(10)	1,387
Net income (loss) attributable to common shareholders (2)	109	15	17	24	(109)	(151)	-	(95)
For the nine months ended September 30, 2016								
Operating revenues from external customers (1)	959	1,002	222	314	231	34	-	2,762
Inter-segment revenues (1)	-	2	-	-	9	19	(28)	2
Total operating revenues	959	1,004	222	314	240	53	(28)	2,764
Net income (loss) attributable to common shareholders (2)	109	96	36	92	(79)	(97)	-	157

(1) All significant intercompany balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes that the elimination of these transactions would understate property, plant and equipment, operating, maintenance and general expenses, or regulated fuel for generation and purchased power. Inter-company transactions which have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.
(2) Corporate and Other net income for the three months ended September 30, 2017 has been increased by amortization of $4 million and for the nine months ended September 30, 2017 by $12 million related to the unregulated long-term debt fair market value adjustment recognized on the acquisition of TECO Energy.
(3) Financial results of Emera Florida and New Mexico are from July 1, 2016, the date of the acquisition.

5. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

Investments subject to significant influence consisted of the following:

	Carrying Value	as at	Equity Income for the three months ended September 30		Equity Income for the nine months ended September 30		Percentage of Ownership
	September 30	December 31					
millions of Canadian dollars	**2017**	2016	**2017**	2016	**2017**	2016	**2017**
LIL (1)	**$ 482**	$ 400	**$ 9**	$ 6	**$ 27**	$ 16	**53.7**
NSPML	**469**	315	**10**	6	**26**	15	**100.0**
M&NP (2)	**159**	175	**6**	6	**17**	17	**12.9**
Lucelec (2)	**37**	39	**-**	1	**2**	2	**19.1**
Bear Swamp (3)	**-**	-	**8**	4	**17**	11	**50.0**
Algonquin Power and Utilities Corp ("APUC") (4)	**-**	-	**-**	-	**-**	18	**-**
Other Investments	**20**	18	**1**	-	**1**	-	**-**
	$ 1,167	$ 947	**$ 34**	$ 23	**$ 90**	$ 79	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.9 per cent of the total units issued.
(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 as a result of a $179 million distribution received in Q4 2015. Bear Swamp's credit investment balance of $191 million (2016 - $217 million) is recorded in "Other long-term liabilities" on the Condensed 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 21). NSPML's consolidated summarized balance sheet is illustrated as follows:

As at	**September 30**	December 31
millions of Canadian dollars	**2017**	2016
Balance Sheet		
Current assets	**$ 336**	$ 439
Property, plant and equipment	**1,567**	1,132
Non-current assets	**86**	276
Total assets	**1,989**	1,847
Current liabilities	**196**	219
Long-term debt	**1,287**	1,288
Non-current liabilities	**37**	25
Equity	**469**	315
Total liabilities and equity	**$ 1,989**	$ 1,847

6. OTHER INCOME (EXPENSES), NET

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Gain on sale of APUC common shares	**$ -**	$ -	**$ -**	$ 172
Gain on conversion of APUC subscription receipts and dividend equivalents to common shares of APUC	**-**	-	**-**	63
Gain on BLPC Self-Insurance Fund ("SIF") regulatory liability	**-**	-	**-**	53
Allowance for equity funds used during construction	**2**	10	**7**	12
Amortization of defeasance costs	**(2)**	(2)	**(5)**	(5)
Foreign exchange gains (losses) and mark-to-market adjustments related to the TECO Energy acquisition	**-**	(2)	**-**	(135)
Other	**(3)**	8	**(2)**	9
	$ (3)	$ 14	**$ -**	$ 169

7. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Interest on debt	**$ 161**	$ 166	**$ 499**	$ 276
Beneficial conversion feature (1)	**-**	62	**-**	62
Interest on Convertible Debentures (1)	**-**	-	**-**	65
Allowance for borrowed funds used during construction	**(2)**	(5)	**(5)**	(7)
Other	**11**	10	**29**	20
	$ 170	$ 233	**$ 523**	$ 416

(1) In 2015, Emera completed the sale of $2.185 billion four per cent convertible unsecured subordinated debentures represented by instalment receipts which were substantially all converted to equity in 2016.

8. INCOME TAXES

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

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Income before provision for income taxes	**$ 144**	$ (120)	**$ 722**	$ 179
Statutory income tax rate	**31%**	31%	**31%**	31%
Income taxes, at statutory income tax rate	**45**	(37)	**224**	56
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(5)**	(8)	**(40)**	(35)
Foreign tax rate variance	**16**	15	**35**	-
Financing deductions	**(4)**	(3)	**(13)**	(11)
Non-taxable portion of gains on APUC transactions	**-**	-	**-**	(36)
Non-deductible portion of foreign exchange and mark-to-market adjustments related to the TECO Energy acquisition	**-**	-	**-**	21
Other	**(7)**	(11)	**(15)**	(11)
Income tax expense (recovery)	**$ 45**	$ (44)	**$ 191**	$ (16)
Effective income tax rate	**31%**	37%	**26%**	(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.

The following reflects the composition of taxes on income from continuing operations presented in the Condensed Consolidated Statements of Income:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Income tax expense (recovery) – current	**$ 19**	$ 12	**$ 48**	$ 35
Income tax expense (recovery) – deferred	**26**	(56)	**143**	(51)
Income tax expense (recovery)	**$ 45**	$ (44)	**$ 191**	$ (16)

NSPI and the Canada Revenue Agency ("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.

9. COMMON STOCK

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

Issued and outstanding:	millions of shares	millions of Canadian dollars
Balance, December 31, 2016	210.02	$ 4,738
Conversion of Convertible Debentures (1)	0.14	6
Issued for cash under Purchase Plans at market rate	2.91	135
Discount on shares purchased under Dividend Reinvestment Plan	-	(7)
Options exercised under senior management share option plan	0.07	2
Employee Share Purchase Plan	-	1
Balance, September 30, 2017	**213.14**	**$ 4,875**

(1) As at September 30, 2017, a total of 52.13 million common shares of the Company were issued, representing conversion into common shares of more than 99.9% of the Convertible Debentures.

10. EARNINGS PER SHARE

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

For the millions of Canadian dollars (except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Numerator				
Net income attributable to common shareholders	**$ 81.0**	$ (94.9)	**$ 494.4**	$ 157.2
Convertible Debentures (1)	**-**	-	**-**	0.2
Diluted numerator	**81.0**	(94.9)	**494.4**	157.4
Denominator				
Weighted average shares of common stock outstanding	**212.7**	181.7	**211.6**	159.4
Weighted average deferred share units outstanding	**1.1**	1.1	**1.1**	1.1
Weighted average shares of common stock outstanding – basic	**213.8**	182.8	**212.7**	160.5
Stock-based compensation (1)	**0.6**	-	**0.5**	0.6
Dividend reinvestment plan (1)	**0.8**	-	**0.8**	0.6
Convertible Debentures (1)	**0.1**	-	**0.1**	0.3
Weighted average shares of common stock outstanding – diluted	**215.3**	182.8	**214.1**	162.0
Earnings per common share				
Basic	**$ 0.38**	$ (0.52)	**$ 2.32**	$ 0.98
Diluted	**$ 0.38**	$ (0.52)	**$ 2.31**	$ 0.97

(1) The following potential common shares were excluded from diluted EPS for the three months ended September 30, 2016 as the Company had a net loss for the quarter: 0.6 million related Stock-based compensation, 0.6 million related to Dividend reinvestment plan and 0.3 million related to the Company's 0.5% convertible debentures common shares that has a dilutive effect.

11. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of accumulated other comprehensive income (loss), net of tax, 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 in available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the nine months ended September 30, 2017						
Balance, January 1, 2017	$ 486	$ (49)	$ (21)	$ (1)	$ (309)	$ 106
Other comprehensive income (loss) before reclassifications	(489)	103	11	7	-	(368)
Amounts reclassified from accumulated other comprehensive income loss (gain)	-	-	5	(2)	21	24
Net current period other comprehensive income (loss)	(489)	103	16	5	21	(344)
Balance, September 30, 2017	$ (3)	$ 54	$ (5)	$ 4	$ (288)	$ (238)

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 in available-for-sale investments	Net change in unrecognized pension and post-retirement benefit costs	Total AOCI
For the nine months ended September 30, 2016						
Balance, January 1, 2016	$ 489	$ -	$ (35)	$ -	$ (317)	$ 137
Other comprehensive income (loss) before reclassifications	(117)	(13)	14	3	-	(113)
Amounts reclassified from accumulated other comprehensive income loss (gain)	-	-	7	(4)	29	32
Equity method reclassification adjustments	(36)	-	(7)	-	(3)	(46)
Net current period other comprehensive income (loss)	(153)	(13)	14	(1)	26	(127)
Other	(4)	-	-	-	-	(4)
Balance, September 30, 2016	$ 332	$ (13)	$ (21)	$ (1)	$ (291)	$ 6

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

For the		Three months ended September 30		Nine months ended September 30	
millions of Canadian dollars		**2017**	2016	**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	**$ -**	$ 1	**$ (3)**	$ (2)
Interest rate swaps	Income from equity investments	**-**	-	**-**	1
Foreign exchange forwards	Operating revenue – regulated	**1**	3	**7**	8
Total before tax		**1**	4	**4**	7
	Income tax expense (recovery)	**-**	(1)	**1**	
Total net of tax		**$ 1**	$ 3	**$ 5**	$ 7
Net change in available-for-sale investments					
	Other income (expenses), net	**(1)**	(4)	**(2)**	(4)
Total before tax		**(1)**	(4)	**(2)**	(4)
	Income tax expense (recovery)	**-**	-	**-**	-
Total net of tax		**(1)**	(4)	**(2)**	(4)
Net change in unrecognized pension and post-retirement benefit costs					
Actuarial losses (gains)	OM&G	**$ 10**	$ 13	**$ 25**	$ 34
Past service costs (gains)	OM&G	**(2)**	(2)	**(6)**	(7)
Total before tax		**8**	11	**19**	27
	Income tax expense (recovery)	**-**	2	**2**	2
Total net of tax		**$ 8**	$ 13	**$ 21**	$ 29
Total reclassifications out of AOCI, net of tax, for the period		**$ 8**	$ 12	**$ 24**	$ 78

12. DERIVATIVE INSTRUMENTS

The Company enters into futures, forwards, swaps and option contracts as part of its risk management strategy to limit exposure to:

- commodity price fluctuations related to the purchase and sale of commodities in the course of normal operations;
- foreign exchange fluctuations on foreign currency denominated purchases and sales; and
- interest rate fluctuations on debt securities.

The Company also enters into physical contracts for energy commodities. Collectively, these contracts are considered “derivatives”. The Company accounts for derivatives under one of the following four approaches:

1. Physical contracts that meet the normal purchases normal sales (“NPNS”) exemption are not recognized on the balance sheet; they are recognized in income when they settle. A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to the Company’s business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty credit worthy. The Company continually assesses contracts designated under the NPNS exemption and will discontinue the treatment of these contracts under this exception if the criteria are no longer met.

2. Derivatives that qualify for hedge accounting are recorded at fair value on the balance sheet. Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge the identified cash flow risk both at the inception and over the term of the derivative. 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 fair value from cash flow hedges is recognized in net income in the reporting period.

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

3. Derivatives entered into by Tampa Electric, PGS, NMGC, NSPI, Emera Maine and GBPC that are documented as economic hedges, and for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The gain or loss is recognized in the hedged item when the hedged item is settled. Management believes that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates.

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

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

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**September 30 2017**	December 31 2016	**September 30 2017**	December 31 2016
Current				
Cash flow hedges				
Power swaps	**$ 5**	$ 5	**$ 2**	$ 2
Foreign exchange forwards	**-**	-	**7**	12
	5	5	**9**	14
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**52**	26	**9**	9
Power purchases	**2**	3	**1**	1
Natural gas purchases and sales	**4**	28	**1**	-
Heavy fuel oil purchases	**3**	6	**4**	4
Foreign exchange forwards	**21**	56	**-**	-
Physical natural gas and biofuel energy purchases and sales	**-**	-	**2**	-
	82	119	**17**	14
HFT derivatives				
Power swaps and physical contracts	**71**	33	**71**	44
Natural gas swaps, futures, forwards, physical contracts	**90**	93	**168**	357
	161	126	**239**	401
Other derivatives				
Foreign exchange forwards	**-**	-	**-**	1
	-	-	**-**	1
Total gross current derivatives	**248**	250	**265**	430
Impact of master netting agreements with intent to settle net or simultaneously	**(120)**	(105)	**(120)**	(105)
Total current derivatives	**128**	145	**145**	325
Long-term				
Cash flow hedges				
Power swaps	**1**	5	**-**	3
Foreign exchange forwards	**2**	-	**1**	10
	3	5	**1**	13
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**49**	57	**1**	-
Power purchases	**2**	4	**2**	3
Natural gas purchases and sales	**1**	5	**2**	2
Heavy fuel oil purchases	**4**	4	**1**	3
Foreign exchange forwards	**15**	50	**4**	-
	71	120	**10**	8
HFT derivatives				
Power swaps and physical contracts	**18**	14	**22**	27
Natural gas swaps, futures, forwards and physical contracts	**34**	18	**77**	127
	52	32	**99**	154
Other derivatives				
Interest rate swap	**2**	-	**-**	1
	2	-	**-**	1
Total gross long-term derivatives	**128**	157	**110**	176
Impact of master netting agreements with intent to settle net or simultaneously	**(27)**	(26)	**(27)**	(26)
Total long-term derivatives	**101**	131	**83**	150
Total derivatives	**$ 229**	$ 276	**$ 228**	$ 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 Condensed Consolidated Balance Sheets, are summarized in the following table:

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**September 30 2017**	December 31 2016	**September 30 2017**	December 31 2016
Regulatory deferral	**$ 11**	$ 10	**$ 11**	$ 10
HFT derivatives	**136**	121	**136**	121
Total impact of master netting agreements with intent to settle net or simultaneously	**$ 147**	$ 131	**$ 147**	$ 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.

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

For the millions of Canadian dollars			**2017**	Three months ended September 30		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	**$ -**	**$ -**	**$ -**	$ (1)	$ -	$ -
Realized gain (loss) in operating revenue – regulated	**-**	**-**	**(1)**		-	(3)
Total gains (losses) in net income	**$ -**	**$ -**	**$ (1)**	$ (1)	$ -	$ (3)

For the millions of Canadian dollars			**2017**	Nine months ended September 30		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	**-**	**-**	**(7)**	-	-	(8)
Realized gain (loss) in income from equity investments	**-**	**-**	**-**	-	(1)	-
Total gains (losses) in net income	**$ 3**	**$ -**	**$ (7)**	$ 2	$ (1)	$ (8)

As at millions of Canadian dollars			**September 30 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	**$ -**	**$ -**	**$ (5)**	$ 2	$ -	$ (22)

The Company expects $9 million of unrealized losses currently in AOCI to be reclassified into net income within the next 12 months, as the underlying hedged transactions settle.

As at September 30, 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	**2017**	2018	2019	2020	2021
Foreign exchange forwards (USD) sales	$ **13**	$ 45	$ 30	$ 30	$ -

Regulatory Deferral

As previously noted, Tampa Electric, PGS, NMGC, NSPI, Emera Maine and GBPC defer gains and losses on certain derivatives documented as economic hedges, including certain physical contracts that do not qualify for the NPNS exemption.

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

For the millions of Canadian dollars	**2017**			Three months ended September 30 2016		
	Commodity swaps and forwards	**Physical natural gas and biofuel energy purchases and sales**	**Foreign exchange forwards**	Commodity swaps and forwards	Physical natural gas purchases and sales	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ (3)**	**$ 2**	**$ (2)**	$ (3)	$ -	$ (2)
Unrealized gain (loss) in regulatory liabilities	**22**	**-**	**(15)**	17	-	3
Realized (gain) loss in regulatory assets	**-**	**-**	**-**	1	-	5
Realized (gain) loss in regulatory liabilities	**-**	**-**	**-**	-	-	(4)
Realized (gain) loss in inventory (1)	**(4)**	**-**	**(3)**	-	-	(6)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**2**	**-**	**(3)**	4	-	(2)
Total change in derivative instruments	**$ 17**	**$ 2**	**$ (23)**	$ 19	$ -	$ (6)

(1) Realized (gains) losses will be recognized in regulated 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.

For the millions of Canadian dollars	Nine months ended September 30 **2017**			2016		
	Commodity swaps and forwards	**Physical natural gas and biofuel energy purchases and sales**	**Foreign exchange forwards**	Commodity swaps and forwards	Physical natural gas purchases and sales	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ (30)**	**$ (3)**	**$ (4)**	$ 15	$ -	$ -
Unrealized gain (loss) in regulatory liabilities	**30**	**1**	**(32)**	66	(1)	(42)
Realized (gain) loss in regulatory assets	**-**	**-**	**-**	1	-	8
Realized (gain) loss in regulatory liabilities	**(1)**	**-**	**-**	-	-	(6)
Realized (gain) loss in inventory (1)	**(12)**	**-**	**(26)**	3	-	(39)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(2)**	**-**	**(12)**	15	-	(15)
Total change in derivative instruments	**$ (15)**	**$ (2)**	**$ (74)**	$ 100	$ (1)	$ (94)

(1) Realized (gains) losses will be recognized in regulated 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 September 30, 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	**2017** **Purchases**	2018-2020 Purchases
Coal (metric tonnes)	**-**	2
Natural Gas (Mmbtu)	**12**	42
Heavy fuel oil (bbls)	**-**	2

Foreign Exchange Swaps and Forwards

As at September 30, 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:

	2017	2018-2020
Foreign exchange contracts (millions of US dollars)	**$ 42**	$ 284
Weighted average rate	**1.1069**	1.1496
% of USD requirements	**70%**	54%

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	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Power swaps and physical contracts in non-regulated operating revenues	**$ (2)**	$ 4	**$ 4**	$ 1
Natural gas swaps, forwards, futures, physical contracts in non-regulated operating revenues	**28**	(42)	**405**	219
Natural gas swaps, forwards, futures and physical contracts in non-regulated fuel for purchased power	**-**	1	**8**	2
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**(1)**	(4)	**(2)**	(2)
Foreign exchange options in non-regulated operating revenue	**-**	-	**-**	(1)
	$ 25	$ (41)	**$ 415**	$ 219

As at September 30, 2017, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	**2017**	2018	2019	2020	2021
Natural gas purchases (Mmbtu)	**114**	200	122	66	44
Natural gas sales (Mmbtu)	**111**	128	34	11	1
Power purchases (MWh)	**2**	5	2	-	-
Power sales (MWh)	**6**	5	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 for which documentation requirements have not been met:

For the millions of Canadian dollars	**2017**		Three months ended September 30 2016	
	Interest rate swaps	**Foreign exchange forwards**	Interest rate swaps	Foreign exchange forwards
Unrealized gain (loss) in other income (expense)	**$ -**	**$ -**	$ -	$ 102
Realized gain (loss) in other income (expense)	**-**	**-**	-	(87)
Unrealized gain (loss) in interest expense, net	**2**	**-**	-	-
Total gains (losses) in net income	**$ 2**	**$ -**	$ **-**	$ **15**

For the millions of Canadian dollars	**2017**		Nine months ended September 30 2016	
	Interest rate swaps	**Foreign exchange forwards**	Interest rate swaps	Foreign exchange forwards
Unrealized gain (loss) in other income (expense)	**$ -**	**$ -**	$ -	$ -
Realized gain (loss) in other income (expense)	**-**	**-**	-	(87)
Unrealized gain (loss) in interest expense, net	**3**	**-**	-	-
Total gains (losses) in net income	**$ 3**	**$ -**	$ **-**	$ **(87)**

As at September 30, 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.

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 Company also obtains cash deposits from electric customers. 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 September 30, 2017, the Company had $93 million (December 31, 2016 - $104 million) in financial assets considered to be past due, which have been outstanding for an average 72 days. The fair value of these financial assets is $80 million (December 31, 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.

Cash Collateral

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

As at millions of Canadian dollars	**September 30 2017**	December 31 2016
Cash collateral provided to others	**$ 59**	$ 91
Cash collateral received from others	**67**	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 September 30, 2017, the total fair value of these derivatives, in a liability position, was $228 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.

13. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exemption (see note 12), 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				September 30, 2017
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash flow hedges				
Power swaps	**$ 6**	**$ -**	**$ -**	**$ 6**
Foreign exchange forwards	**-**	**2**	**-**	**2**
	6	**2**	**-**	**8**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**92**	**-**	**92**
Power purchases	**4**	**-**	**-**	**4**
Natural gas purchases and sales	**1**	**3**	**-**	**4**
Heavy fuel oil purchases	**1**	**5**	**-**	**6**
Foreign exchange forwards	**-**	**36**	**-**	**36**
Physical natural gas purchases and sales	**-**	**-**	**-**	**-**
	6	**136**	**-**	**142**
HFT derivatives				
Power swaps and physical contracts	**7**	**-**	**10**	**17**
Natural gas swaps, futures, forwards, physical contracts and related transportation	**(1)**	**33**	**28**	**60**
	6	**33**	**38**	**77**
Other derivatives				
Interest rate swap	**-**	**2**	**-**	**2**
	-	**2**	**-**	**2**
Total assets	**18**	**173**	**38**	**229**
Liabilities				
Cash flow hedges				
Power swaps	**3**	**-**	**-**	**3**
Foreign exchange forwards	**-**	**7**	**-**	**7**
	3	**7**	**-**	**10**
Regulatory deferral				
Commodity swaps and forwards				
Power purchases	**3**	**-**	**-**	**3**
Heavy fuel oil purchases	**-**	**3**	**-**	**3**
Natural gas purchases and sales	**2**	**1**	**-**	**3**
Foreign exchange forwards	**-**	**4**	**-**	**4**
Physical natural gas and biofuel energy purchases and sales	**-**	**3**	**-**	**3**
	5	**11**	**-**	**16**
HFT derivatives				
Power swaps and physical contracts	**20**	**-**	**-**	**20**
Natural gas swaps, futures, forwards and physical contracts	**-**	**39**	**143**	**182**
	20	**39**	**143**	**202**
Total liabilities	**28**	**57**	**143**	**228**
Net assets (liabilities)	**$ (10)**	**$ 116**	**$ (105)**	**$ 1**

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 three months ended September 30, 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, beginning of period	**$ -**	**$ 1**	**$ 15**	**$ 29**	**$ 45**
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	**-**	**(1)**	**-**	**-**	**(1)**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**-**	**(5)**	**(1)**	**(6)**
Balance, September 30, 2017	**$ -**	**$ -**	**$ 10**	**$ 28**	**$ 38**

The change in the fair value of the Level 3 financial liabilities for the three months ended September 30, 2017 was as follows:

	Regulatory Deferral		*HFT Derivatives*		
millions of Canadian dollars	Oil financial derivatives	Physical natural gas and biofuel energy purchases and sales	Power	Natural gas	Total
Balance, beginning of period	**$ -**	**$ -**	**$ 8**	**$ 155**	**$ 163**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**-**	**(8)**	**(12)**	**(20)**
Balance, September 30, 2017	**$ -**	**$ -**	**$ -**	**$ 143**	**$ 143**

The change in the fair value of the Level 3 financial assets for the nine months ended September 30, 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, beginning of period	**$ 1**	**$ -**	**$ -**	**$ 39**	**$ 40**
Increase (reduction) in benefit included in regulated fuel for generation and purchased power	**(1)**	**-**	**-**	**-**	**(1)**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**-**	**10**	**4**	**14**
Net transfers out of Level 3	**-**	**-**	**-**	**(15)**	**(15)**
Balance, September 30, 2017	**$ -**	**$ -**	**$ 10**	**$ 28**	**$ 38**

The change in the fair value of the Level 3 financial liabilities for the nine months ended September 30, 2017 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ -**	**$ 389**	**$ 389**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**(1)**	**(250)**	**(251)**
Net transfers into Level 3	**1**	**4**	**5**
Balance, September 30, 2017	**$ -**	**$ 143**	**$ 143**

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 three months ended September 30, 2017, there were no transfers between levels. For the nine months ended September 30, 2017, transfers out of Level 3 were a result of an increase in observable inputs. For the nine months ended September 30, 2017, transfers into Level 3 were a result of a decrease in observable inputs.

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

Contracts with quoted prices available in active markets and exchanges for identical assets or liabilities are classified as Level 1 in the hierarchy. Those contracts whereby pricing inputs are either directly or indirectly observable through markets, exchanges or third party sources, but do not qualify as Level 1, are classified as Level 2 in the hierarchy. For a Level 3 classification, the processes and methods of measurement for third-party pricing information and illiquid markets are developed with input and using the market knowledge of the trading operations within Emera and its affiliates.

Significant unobservable inputs used in the fair value measurement of Emera's natural gas and power derivatives 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.

As at					**September 30, 2017**
millions of Canadian dollars	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets					
HFT derivatives –	**10**	Modelled pricing	Third-party pricing	\$20.36 - \$82.00	\$56.37
Power swaps and			Probability of default	0.00% - 0.01%	0.00%
physical contracts			Discount rate	0.00% - 0.13%	0.07%
HFT derivatives –	**19**	Modelled pricing	Third-party pricing	\$1.18 - \$5.33	\$2.74
Natural gas swaps, futures, forwards,			Probability of default	0.00% - 0.07%	0.01%
physical contracts			Discount rate	0.00% - 0.29%	0.05%
and related transportation	**9**	Modelled pricing	Third-party pricing	\$1.10 - \$9.62	\$4.21
			Basis adjustment	0.03% - 0.64%	0.55%
			Probability of default	0.00% - 0.10%	0.01%
			Discount rate	0.00% - 0.08%	0.01%
Total assets	**\$ 38**				
Liabilities					
HFT derivatives –	**136**	Modelled pricing	Third-party pricing	\$0.94 - \$8.93	\$3.49
Natural gas swaps, futures,			Own credit risk	0.00% - 0.01%	0.00%
forwards and physical contracts			Discount rate	0.00% - 0.12%	0.02%
	7	Modelled pricing	Third-party pricing	\$1.44 - \$9.62	\$4.77
			Basis adjustment	0.08% - 0.64%	0.03%
			Own credit risk	0.00% - 0.01%	0.00%
			Discount rate	0.00% - 0.08%	0.01%
Total liabilities	**\$ 143**				
Net assets (liabilities)	**\$ (105)**				

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

As at						**September 30, 2017**
millions of Canadian dollars	**Carrying Amount**	**Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Total**
Long-term debt (including current portion)	**$ 14,161**	**$ 15,368**	**$ 70**	**$ 14,508**	**$ 790**	**$ 15,368**

As at						December 31, 2016
millions of Canadian dollars	Carrying Amount	Fair Value	Level 1	Level 2	Level 3	Total
Long-term debt (including current portion)	**$** 14,744	$ 15,723	$ 78	$ 14,843	$ 802	$ 15,723

The fair values 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 $51 million was recorded in Other Comprehensive Income for the three months ended September 30, 2017 (2016 – $13 million loss after-tax). An after-tax foreign currency gain of $103 million was recorded in Other Comprehensive Income for the nine months ended September 30, 2017 (2016 – $13 million loss after-tax) There was no ineffectiveness for the three and nine months ended September 30, 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.

14. REGULATORY ASSETS AND LIABILITIES

A summary of the Company's regulatory assets and liabilities is provided below. For a detailed description of the nature of the Company's regulatory assets and liabilities, refer to note 17 in Emera's 2016 annual audited consolidated financial statements.

As at millions of Canadian dollars		**September 30 2017**		December 31 2016
Regulatory assets				
Deferred income tax regulatory assets	**$**	**697**	$	632
Pension and post-retirement medical plan		**351**		373
Environmental remediation		**41**		49
Unamortized defeasance costs		**34**		39
2015 Demand side management deferral		**29**		32
GBPC Hurricane Matthew restoration		**27**		28
Stranded cost recovery		**25**		27
Transmission and delivery storm reserve		**17**		-
Deferrals related to derivative instruments		**14**		15
Debt basis adjustment		**14**		19
Cost-recovery clauses		**11**		12
Deferred bond refinancing costs		**8**		9
Other		**79**		87
	$	**1,347**	$	1,322
Current	**$**	**90**	$	80
Long-term		**1,257**		1,242
Total regulatory assets	**$**	**1,347**	$	1,322
Regulatory liabilities				
Accumulated reserve - cost of removal	**$**	**895**	$	990
Regulated fuel adjustment mechanism		**155**		94
Deferrals related to derivative instruments		**139**		230
Cost-recovery clauses		**53**		153
Transmission and delivery storm reserve		**-**		75
Deferred income tax regulatory liabilities		**33**		26
Self-insurance fund (notes 6 and 21)		**27**		30
Bill reduction credit		**5**		10
Other		**25**		31
	$	**1,332**	$	1,639
Current	**$**	**200**	$	362
Long-term		**1,132**		1,277
Total regulatory liabilities	**$**	**1,332**	$	1,639

Transmission and Delivery Storm Reserve

The transmission and delivery storm reserve is for hurricanes and other named storms that cause significant damage to Tampa Electric's system. On September 10, 2017, Tampa Electric was impacted by Hurricane Irma resulting in 57 per cent of Tampa Electric's customers losing power, of which substantially all were back within seven days. Estimated cost of restoration is $70 million USD, of which $60 million USD was charged to the transmission and delivery storm reserve, $6 million USD was charged to capital expenditures, and $4 million USD was charged to OM&G expenses. The $60 million USD charged to the storm reserve exceeded the $46 million USD balance by $14 million USD, which has been recorded as a regulatory asset on the balance sheet. Based on an FPSC order, if charges to the storm reserve exceed the account balance, the excess shall be carried as a regulatory asset. Tampa Electric expects to petition the FPSC in early 2018 for recovery of the storm costs in excess of the reserve of $14 million USD and replenish the balance in the reserve to the $56 million USD level that existed as of October 31, 2013.

Regulated Fuel Adjustment Mechanism

Differences between actual Fuel Costs and amounts recovered from NSPI customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

On 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 forecasted in service date is January 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 $18 million, 2019 of approximately $36 million and 2020 of approximately $53 million, as the payments from NSPI to NSPML are not required. As of September 30, 2017, NSPI collected $12 million of these recoveries from customers, which is recorded as part of the FAM regulatory liability.

Dominica Electricity Services Limited

On September 19, 2017, Dominica experienced unprecedented damage as a result of Hurricane Maria, facing winds of 175 miles per hour. All 36,000 of Domlec's customers lost power. Domlec has begun restoring power to specific vital services and will continue to work with the Government of Dominica to identify the next priorities for restoration. The country's overall restoration plan for the island's infrastructure is not yet completed, and as a result, the Company is unable to estimate the possible financial loss, range of financial loss or recovery related to this storm.

15. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera provides energy, construction and other services and enters into transactions with its subsidiaries, associates and other related companies on terms similar to those offered to non-related parties. Inter-company balances and inter-company transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. All material amounts are under normal interest and credit terms.

Significant transactions between Emera and its associated companies include:

- Natural gas transportation capacity revenues from M&NP reported in the Condensed Consolidated Statements of Income. Revenues from M&NP, reported in Operating revenues, Non-regulated, totalled $4 million for the three months ended September 30, 2017 (2016 - $6 million) and $20 million for the nine months ended September 30, 2017 (2016 - $21 million).
- Transmission construction revenues from NSPML reported in the Condensed Consolidated Statements of Income. Revenues from NSPML, reported in Operating revenues, Non-regulated, totalled nil for the three months ended September 30, 2017 (2016 - nil) and $13 million for the nine months ended September 30, 2017 (2016 - nil).

There are no significant amounts between Emera and its associated companies reported on Emera's Condensed Consolidated Balance Sheets as at September 30, 2017 and December 31, 2016.

16. 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. For details of the Company's employee benefit plan, refer to note 21 in Emera's 2016 annual audited consolidated financial statements.

The net benefit cost of providing the defined benefit pension and non-pension benefit plans is detailed below:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Defined benefit pension plans				
Service cost	**$ 12**	$ 12	**$ 36**	$ 23
Interest cost	**25**	24	**75**	54
Expected return on plan assets	**(31)**	(31)	**(97)**	(64)
Current year amortization of:				
Actuarial losses (gains)	**10**	10	**29**	31
Past service costs (gains)	**(1)**	-	**(1)**	(1)
Regulated asset (liability)	**3**	5	**12**	**5**
Total defined benefit pension plans	**18**	20	**54**	48
Non-pension benefits plan				
Service cost	**1**	1	**4**	3
Interest cost	**4**	4	**11**	5
Expected return on plan assets	**(1)**	(1)	**(2)**	(1)
Current year amortization of:				
Actuarial losses (gains)	**1**	1	**2**	2
Past service costs (gains)	**(2)**	(2)	**(6)**	(6)
Regulated asset (liability)	**-**	-	**(1)**	**-**
Total non-pension benefits plans	**3**	3	**8**	3
Total defined benefit plans	**$ 21**	$ 23	**$ 62**	$ 51

17. 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. For details regarding short-term debt refer to note 24 in Emera's 2016 annual audited consolidated financial statements and below for recent 2017 financing activities.

Recent financing activities

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.

18. LONG-TERM DEBT

For details regarding long-term debt refer to note 26 in Emera's 2016 annual audited consolidated financial statements and below for recent 2017 financing activities.

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% 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% and 5.875% from 6.65% and 6.875%, respectively.

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 September 30, 2017 a total of $30 million USD was drawn against the new facilities.

19. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at September 30, 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	2017	2018	2019	2020	2021	Thereafter	Total
Purchased power (1)	$ 86	$ 229	$ 214	$ 210	$ 207	$ 2,338	$ 3,284
Transportation (2)	116	402	298	264	184	1,517	2,781
Fuel and gas supply	185	257	129	47	37	-	655
Long-term service agreements (3)	47	66	67	34	43	220	477
Equity investment commitments (4)	230	15	-	190	-	-	435
Leases and other (5)	22	40	11	10	6	64	153
Capital projects	78	225	87	-	-	-	390
Demand side management	18	90	10	-	-	-	118
	$ 782	$ 1,324	$ 816	$ 755	$ 477	$ 4,139	$ 8,293

(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”)

On December 19, 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.

On April 18, 2014, Guatemala filed an application for annulment of the entire Award (or, alternatively, certain parts of the Award) pursuant to applicable ICSID rules.

On April 18, 2014, TGH separately filed an application for partial annulment of the Award on the basis of certain deficiencies in the ICSID Tribunal’s determination of the amount of TGH’s damages.

On April 5, 2016, an ICSID ad hoc Committee issued a decision in favour of TGH in the annulment proceedings. In its decision, the ad hoc Committee unanimously dismissed Guatemala’s application for annulment of the award and upheld the original $21 million USD award, plus interest. In addition, the ad hoc Committee granted TGH’s application for partial annulment of the award, and ordered Guatemala 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. 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 September 30, 2017, TEC has estimated its ultimate financial liability to be $37 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 Condensed 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

On September 30, 2011, a group including the Attorney General of Massachusetts, New England utilities commissions, state public advocates and end users filed a complaint with the FERC alleging that the 11.14 per cent base ROE under the ISO-New England ("ISO-NE") Open Access Transmission Tariff ("OATT") was unjust and unreasonable.

On June 19, 2014, the FERC issued an order (the "FERC Order") in connection with this complaint that changed the methodology used to set the ROE and resulted in a lower base transmission ROE of 10.57 per cent and a lower total ROE (inclusive of incentive adders) of 11.74 per cent for the period of October 1, 2011 to December 31, 2012. The ROE was confirmed by FERC in two subsequent orders and the FERC Order was appealed by a group of New England Transmission Owners, including Emera Maine and by customers, to the U.S. Court of Appeals for the District of Columbia Circuit. On June 30, 2016, Emera Maine completed the processing of refunds to customers to reflect the 10.57 per cent ROE. On April 14, 2017, the U.S. Court of Appeals vacated the FERC Order. The Court concluded that FERC failed to make an explicit finding that the existing base ROE of 11.14 per cent was unjust and unreasonable, and failed to provide any reasoned basis for selecting 10.57 per cent as the new base ROE. The Court remanded the case to the FERC for further proceedings consistent with the Court's order.

On December 27, 2012, a second group of consumer advocates, including Environment Northeast, filed a complaint with the FERC on similar grounds, arguing that the 11.14 per cent base ROE under the OATT was unjust and unreasonable ("the ENE Case"). This complaint applies to the period from January 1, 2013 to March 31, 2014. On July 31, 2014, a group of state commissions, state public advocates and end users filed a third complaint with the FERC on similar grounds ("the MA AG II Case") in relation to the period from July 31, 2014 to October 31, 2015. The ENE Case and MA AG II Case were subsequently consolidated by FERC into a single case.

On March 22, 2016, a FERC Administrative Law Judge ("ALJ") issued a recommended decision to FERC with respect to the consolidated cases. The recommendation for the ENE Case was a 9.59 per cent base ROE, with a 10.42 per cent maximum ROE, and the recommendation for the MA AG II Case was a 10.90 per cent base ROE, with a 12.19 per cent maximum ROE. The ALJ's recommended decision is not definitive and FERC has the ability to adjust the ALJ's recommended decision. A decision by FERC is not expected until Q1 2018.

On April 29, 2016, an additional complaint was filed with FERC challenging the ROE under the ISO-NE transmission tariff. The complaint was filed by the Eastern Massachusetts Consumer-Owned Systems ("EMCOS"), a collection of thirteen municipal light departments, seeking to reduce the base ROE to 8.61 per cent and the maximum ROE to 11.24 per cent for the period April 29, 2016 to July 29, 2017.

Emera Maine has recorded a reserve of $4 million USD for the ENE Case and MA AG II Case. The reserves recorded for these complaints have been recorded as "Regulatory liabilities" on the Condensed Consolidated Balance Sheets and as a reduction to "Operating revenues – regulated electric" on the Condensed Consolidated Statements of Income. The reserve was calculated on a 10.57 per cent base and represents Emera Maine's best estimate of the probable outcome. No update has been made to the reserve as a result of the ALJ recommendation as it is pending approval by the FERC and is considered uncertain until that time. No reserve has been made as a result of the EMCOS complaint, as the outcome is considered uncertain. No change in reserves has been made in relation to the first FERC ROE complaint as a result of the D.C. Court of Appeals vacating the FERC Order as the outcome is considered uncertain.

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 Risks and Uncertainties

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

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

Regulatory and Political Risk

The Company's rate-regulated businesses and certain investments subject to significant influence are subject to risk of the recovery of costs and investments. As cost-of-service utilities with an obligation to serve customers, Tampa Electric, PGS, NMGC, NSPI (including ENL's Maritime Link Project), Emera Maine, BLPC, GBPC, and Domlec must obtain regulatory approval to change electricity rates and/or riders from their respective regulators. Costs and investments can be recovered upon approval by the respective regulator as an adjustment to rates and/or riders, which normally requires a public hearing process or may be mandated by other governmental bodies. In addition, the commercial and regulatory frameworks under which Emera and its subsidiaries operate can be impacted by significant shifts in government policy (including shifts in policy which could occur as a result of climate change concerns) and changes in governments. Emera's investments in entities in which it has significant influence and which are subject to regulatory risk include: NSPML, LIL, M&NP and Lucelec.

During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these rate-regulated companies and their respective regulators determine whether to allow recovery and to adjust rates based upon the evidence and any contrary evidence from other parties. In some circumstances, other government bodies may influence the setting of rates. The subsidiaries manage this regulatory risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, fuel-related audits, rate filings and capital plans. The subsidiaries employ a collaborative regulatory approach through technical conferences and, where appropriate, negotiated settlements.

Weather and Climate Risk

Shifts in weather patterns affect energy sales and associated revenues and costs. Extreme weather events generally result in increased operating costs associated with restoring service to customers as a result of unplanned outages. Emera responds to outages which occur as a result of significant weather events according to each subsidiary's respective emergency services restoration plan.

Changes in Environmental Legislation

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

In addition to imposing continuing compliance obligations, there are permit requirements, laws and regulations authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is, and may be, material to Emera. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on Emera. In addition, Emera's business could be materially affected by changes in government policy, utility regulation, and environmental and other legislation that could occur in response to environmental and climate change concerns.

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

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

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 capital 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. After giving effect to the TECO Energy acquisition, Emera now has total debt of $15 billion. 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 raise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

Commercial Relationships Risk

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

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.

Enterprise Resource Planning ("ERP") System Risk

In August 2017, Emera's Canadian operating affiliates updated their financial information systems through the implementation of an integrated ERP system. The Company has adopted a detailed plan to address the risks inherent in the implementation of a new financial information system. Potential deficiencies in the design and implementation of the new ERP system could affect Emera's ability to monitor its business, pay its suppliers and prepare its financial statements accurately and on a timely basis. Emera continues to manage this risk through a dedicated project post-implementation activities and hyper-care team, executive oversight, and a detailed governance structure. Consultants, with extensive ERP expertise, have and will continue to assist in project management, post-implementation, hyper-care and training.

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 benefits are determined by existing tax laws and could be negatively impacted by changes in laws. "Comprehensive tax reform" remains a topic of discussion in the U.S. Congress. Such legislation could significantly alter the existing tax code, including a reduction in the corporate income tax rate. Although a reduction in the corporate income tax rate could result in lower 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. 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

Emera's guarantees and letters of credit are consistent with those disclosed in the 2016 audited consolidated financial statements, with the noted updates below.

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 September 30, 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.

Emera has a standby letter of credit in the amount of $21 million to guarantee the performance of the obligations of the EUS-Rokstad joint venture. The letter of credit has been extended, and now expires in November 2017. 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. Rokstad Power has issued a separate letter of credit to Emera for their portion of the work to be performed under the contract. EUS and Rokstad Power are jointly and severally liable for completion of the project.

Emera has standby letters of credit in the amount of $46 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 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 September 30, 2017 was $51 million.

20. SUPPLEMENTARY INFORMATION TO CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of Canadian dollars	Nine months ended September 30 **2017**	2016
Changes in non-cash working capital:		
Receivables, net	**$ 70**	$ 76
Income taxes receivable	**18**	(32)
Inventory	**(5)**	76
Prepayments and other current assets	**(6)**	(18)
Accounts payable	**(71)**	60
Income taxes payable	**(13)**	16
Other current liabilities	**92**	74
Total non-cash working capital	**$ 85**	$ 252
Supplemental disclosure of non-cash activities:		
Common share dividends reinvested	**$ 123**	$ 63
Beneficial Conversion Feature of the convertible debentures	**$ -**	$ 43

21. 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.

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 Condensed Consolidated Balance Sheets.

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 significant unconsolidated VIEs:

As at	**September 30, 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)	**$ 469**	**$ 198**	$ 315	$ 577

22. 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.

23. SUBSEQUENT EVENTS

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.

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through November 10, 2017, the date the financial statements were issued.