

EMERA INCORPORATED

Unaudited Condensed Consolidated

Interim Financial Statements

September 30, 2019 and 2018

Emera Incorporated

Condensed Consolidated Statements of Income (Unaudited)

For the millions of Canadian dollars (except per share amounts)	Three months ended		Nine months ended	
	September 30		September 30	
	2019	2018	2019	2018
Operating revenues				
Regulated electric	\$ 1,220	\$ 1,289	\$ 3,598	\$ 3,624
Regulated gas	199	202	785	749
Non-regulated	(120)	4	112	352
Total operating revenues (note 6)	1,299	1,495	4,495	4,725
Operating expenses				
Regulated fuel for generation and purchased power	388	448	1,207	1,250
Regulated cost of natural gas	52	65	249	267
Non-regulated fuel for generation and purchased power	(4)	49	63	159
Operating, maintenance and general	367	370	1,076	1,139
Provincial, state and municipal taxes	88	89	258	256
Depreciation and amortization	226	236	678	687
Total operating expenses	1,117	1,257	3,531	3,758
Income from operations	182	238	964	967
Income from equity investments (note 7)	38	41	118	121
Other income (expenses), net	(8)	5	11	(16)
Interest expense, net	183	176	557	527
Income before provision for income taxes	29	108	536	545
Income tax expense (recovery) (note 8)	(49)	(33)	18	29
Net income	78	141	518	516
Non-controlling interest in subsidiaries	1	1	3	1
Preferred stock dividends	22	22	45	36
Net income attributable to common shareholders	\$ 55	\$ 118	\$ 470	\$ 479
Weighted average shares of common stock outstanding (in millions) (note 10)				
Basic	241.0	233.7	238.9	232.4
Diluted	242.4	235.2	240.3	233.9
Earnings per common share (note 10)				
Basic	\$ 0.23	\$ 0.51	\$ 1.97	\$ 2.06
Diluted	\$ 0.23	\$ 0.50	\$ 1.96	\$ 2.05
Dividends per common share declared	\$ 1.2000	\$ 1.1525	\$ 2.3750	\$ 2.2825

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		Nine months ended	
	September 30		September 30	
	2019	2018	2019	2018
Net income	\$ 78	\$ 141	\$ 518	\$ 516
Other comprehensive income (loss), net of tax				
Foreign currency translation adjustment	95	(126)	(243)	220
Unrealized gains (losses) on net investment hedges (1) (2)	(19)	25	48	(41)
Cash flow hedges				
Net derivative gains (losses)	-	3	3	5
Less: reclassification adjustment for losses (gains) included in income (3)	1	-	3	(6)
Net effects of cash flow hedges	1	3	6	(1)
Unrealized gains (losses) on available-for-sale investment				
Less: reclassification adjustment for (gains) losses recognized in income	-	-	-	(4)
Net unrealized holding gains (losses)	-	-	-	(4)
Net change in unrecognized pension and post-retirement benefit obligation (4)	3	7	11	26
Other comprehensive income (loss) (5)	80	(91)	(178)	200
Comprehensive income (loss)	158	50	340	716
Comprehensive income (loss) attributable to non-controlling interest	1	-	2	3
Comprehensive income (loss) of Emera Incorporated	\$ 157	\$ 50	\$ 338	\$ 713

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

- (1) Net of tax expense of nil (2018 - \$2 million tax expense) for the three months ended September 30, 2019 and tax expense of nil (2018 - \$7 million tax recovery) for the nine months ended September 30, 2019.
- (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 nil (2018 - nil) for the three months ended September 30, 2019 and tax expense of nil (2018 - \$1 million tax recovery) for the nine months ended September 30, 2019.
- (4) Net of tax expense of nil (2018 - nil) for the three months ended September 30, 2019 and tax expense of \$1 million (2018 - \$1 million tax expense) for the nine months ended September 30, 2019.
- (5) Net of tax expense of nil (2018 - \$2 million tax expense) for the three months ended September 30, 2019 and tax expense of \$1 million (2018 - \$7 million tax recovery) for the nine months ended September 30, 2019.

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at millions of Canadian dollars	September 30 2019	December 31 2018
Assets		
Current assets		
Cash and cash equivalents	\$ 273	\$ 316
Restricted cash	63	56
Inventory	479	474
Derivative instruments (notes 12 and 13)	99	148
Regulatory assets (note 14)	123	165
Receivables and other current assets	1,246	1,620
Assets held for sale (note 4)	85	53
	2,368	2,832
Property, plant and equipment , net of accumulated depreciation and amortization of \$8,345 and \$8,567, respectively	17,867	18,712
Other assets		
Deferred income taxes	218	175
Derivative instruments (notes 12 and 13)	30	19
Regulatory assets (note 14)	1,396	1,404
Net investment in direct financing lease (note 16)	474	475
Investments subject to significant influence (note 7)	1,301	1,316
Goodwill (note 14)	5,979	6,313
Other long-term assets	298	291
Assets held for sale (note 4)	1,634	777
	11,330	10,770
Total assets	\$ 31,565	\$ 32,314

Emera Incorporated Condensed Consolidated Balance Sheets (Unaudited) – Continued

As at millions of Canadian dollars	September 30 2019	December 31 2018
Liabilities and Equity		
Current liabilities		
Short-term debt (note 18)	\$ 958	\$ 1,186
Current portion of long-term debt	717	1,119
Accounts payable	1,061	1,289
Derivative instruments (notes 12 and 13)	275	260
Regulatory liabilities (note 14)	289	251
Other current liabilities	621	428
Liabilities associated with assets held for sale (note 4)	94	20
	4,015	4,553
Long-term liabilities		
Long-term debt (note 19)	13,660	14,292
Deferred income taxes	1,213	1,320
Derivative instruments (notes 12 and 13)	101	105
Regulatory liabilities (note 14)	1,976	2,359
Pension and post-retirement liabilities (note 17)	519	641
Other long-term liabilities	802	684
Long-term liabilities associated with assets held for sale (note 4)	906	2
	19,177	19,403
Equity		
Common stock (note 9)	6,115	5,816
Cumulative preferred stock	1,004	1,004
Contributed surplus	78	84
Accumulated other comprehensive income (note 11)	161	338
Retained earnings	980	1,075
Total Emera Incorporated equity	8,338	8,317
Non-controlling interest in subsidiaries (note 21)	35	41
Total equity	8,373	8,358
Total liabilities and equity	\$ 31,565	\$ 32,314

Commitments and contingencies (note 20)

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

Approved on behalf of the Board of Directors

“M. Jacqueline Sheppard”

Chair of the Board

“Scott Balfour”

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	
	2019	2018
Operating activities		
Net income	\$ 518	\$ 516
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	684	695
Income from equity investments, net of dividends	(60)	(64)
Allowance for equity funds used during construction	(14)	(14)
Deferred income taxes, net	82	8
Net change in pension and post-retirement liabilities	(26)	(1)
Regulated fuel adjustment mechanism	(20)	(10)
Net change in fair value of derivative instruments	(51)	122
Net change in regulatory assets and liabilities	19	64
Net change in capitalized transportation capacity	42	(79)
Other operating activities, net	8	-
Changes in non-cash working capital (note 22)	128	156
Net cash provided by operating activities	1,310	1,393
Investing activities		
Proceeds from dispositions (note 4)	866	-
Additions to property, plant and equipment	(1,647)	(1,544)
Net purchase of investments subject to significant influence, inclusive of acquisition costs	(3)	(43)
Other investing activities	(2)	22
Net cash used in investing activities	(786)	(1,565)
Financing activities		
Change in short-term debt, net	(188)	91
Proceeds from short-term debt with maturities greater than 90 days	-	129
Proceeds from long-term debt, net of issuance costs	841	488
Retirement of long-term debt	(851)	(728)
Net borrowings (repayments) under committed credit facilities	(165)	152
Issuance of common stock, net of issuance costs	151	8
Issuance of preferred stock, net of issuance costs	-	291
Dividends on common stock	(278)	(256)
Dividends on preferred stock	(34)	(24)
Other financing activities	(22)	(30)
Net cash (used in) provided by financing activities	(546)	121
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	(13)	11
Net decrease in cash, cash equivalents, restricted cash and assets held for sale	(35)	(40)
Cash, cash equivalents, restricted cash and assets held for sale, beginning of period	372	503
Cash, cash equivalents, restricted cash and assets held for sale, end of period	\$ 337	\$ 463
Cash, cash equivalents, restricted cash, and assets held for sale consists of:		
Cash	\$ 266	\$ 319
Short-term investments	7	74
Restricted cash	63	70
Assets held for sale	1	-
Cash, cash equivalents, restricted cash, and assets held for sale	\$ 337	\$ 463

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	Non- Controlling Interest	Total Equity
For the three months ended September 30, 2019							
Balance, June 30, 2019	\$ 6,010	\$ 1,004	\$ 79	\$ 81	\$ 1,212	\$ 35	\$ 8,421
Net income of Emera Incorporated	-	-	-	-	77	1	78
Other comprehensive income (loss), net of tax expense of nil	-	-	-	80	-	-	80
Dividends declared on preferred stock (1)	-	-	-	-	(22)	-	(22)
Dividends declared on common stock (\$1.2000/share)	-	-	-	-	(287)	-	(287)
Common stock issued under purchase plan	45	-	-	-	-	-	45
Issuance of common stock, net of after-tax issuance costs	49	-	-	-	-	-	49
Senior management stock options exercised	10	-	(1)	-	-	-	9
Other	1	-	-	-	-	(1)	-
Balance, September 30, 2019	\$ 6,115	\$ 1,004	\$ 78	\$ 161	\$ 980	\$ 35	\$ 8,373

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss) ("AOCI")	Retained Earnings	Non- Controlling Interest	Total Equity
For the nine months ended September 30, 2019							
Balance, December 31, 2018	\$ 5,816	\$ 1,004	\$ 84	\$ 338	\$ 1,075	\$ 41	\$ 8,358
Net income of Emera Incorporated	-	-	-	-	515	3	518
Other comprehensive income (loss), net of tax expense of \$1 million	-	-	-	(177)	-	(1)	(178)
Dividends declared on preferred stock (2)	-	-	-	-	(45)	-	(45)
Dividends declared on common stock (\$2.3750/share)	-	-	-	-	(565)	-	(565)
Issuance of preferred shares of GBPC, net of issuance costs (note 21)	-	-	-	-	-	14	14
Redemption of preferred shares of GBPC (note 21)	-	-	-	-	-	(19)	(19)
Common stock issued under purchase plan	146	-	-	-	-	-	146
Issuance of common stock, net of after-tax issuance costs	49	-	-	-	-	-	49
Senior management stock options exercised	103	-	(6)	-	-	-	97
Other	1	-	-	-	-	(3)	(2)
Balance, September 30, 2019	\$ 6,115	\$ 1,004	\$ 78	\$ 161	\$ 980	\$ 35	\$ 8,373

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

(1) Series A; \$0.31940/share, Series B; \$0.44060/share, Series C; \$0.59012/share, Series E; \$0.56250/share, Series F; \$0.53125/share and Series H; \$0.61250/share

(2) Series A; \$0.63880/share, Series B; \$0.87270/share, Series C; \$1.18024/share, Series E; \$1.12500/share, Series F; \$1.06250/share and Series H; \$1.22500

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) ("AOI")	Retained Earnings	Non- Controlling Interest	Total Equity
For the three months ended September 30, 2018							
Balance, June 30, 2018	\$ 5,724	\$ 1,004	\$ 82	\$ 123	\$ 997	\$ 40	\$ 7,970
Net income of Emera Incorporated	-	-	-	-	140	1	141
Other comprehensive income (loss), net of tax expense of \$2 million	-	-	-	(90)	-	(1)	(91)
Dividends declared on preferred stock (1)	-	-	-	-	(22)	-	(22)
Dividends declared on common stock (\$1.1525/share)	-	-	-	-	(268)	-	(268)
Common stock issued under purchase plan	43	-	-	-	-	-	43
Acquisition of non-controlling interest of ECI	-	-	1	-	-	-	1
Other	1	-	-	-	-	-	1
Balance, September 30, 2018	\$ 5,768	\$ 1,004	\$ 83	\$ 33	\$ 847	\$ 40	\$ 7,775

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	Accumulated Other Comprehensive Income (Loss) ("AOI")	Retained Earnings	Non- Controlling Interest	Total Equity
For the nine months ended September 30, 2018							
Balance, December 31, 2017	\$ 5,601	\$ 709	\$ 76	\$ (165)	\$ 891	\$ 92	\$ 7,204
Net income of Emera Incorporated	-	-	-	-	515	1	516
Other comprehensive income (loss), net of tax recovery of \$7 million	-	-	-	198	-	2	200
Dividends declared on preferred stock (2)	-	-	-	-	(36)	-	(36)
Dividends declared on common stock (\$2.2825/share)	-	-	-	-	(528)	-	(528)
Issuance of preferred shares, net of after-tax issuance costs	-	295	-	-	-	-	295
Common stock issued under purchase plan	143	-	-	-	-	-	143
Acquisition of non-controlling interest of ECI	22	-	6	-	-	(53)	(25)
Other	2	-	1	-	5	(2)	6
Balance, September 30, 2018	\$ 5,768	\$ 1,004	\$ 83	\$ 33	\$ 847	\$ 40	\$ 7,775

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

(1) Series A; \$0.31940/share, Series B; \$0.39480/share, Series C; \$0.55131/share, Series E; \$0.56250/share, Series F; \$0.53125/share, and Series H; \$0.56132/share

(2) Series A; \$0.63880/share, Series B; \$0.75700/share, Series C; \$1.06381/share, Series E; \$1.12500/share, Series F; \$1.06250/share and Series H; \$0.56132/share

Emera Incorporated
Notes to the Condensed Consolidated Interim Financial Statements (Unaudited)
As at September 30, 2019 and 2018

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

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

Effective January 1, 2019, Emera has revised its reportable segments to align with strategic priorities and internal governance. These new reporting segments align with how the Company assesses financial performance and makes decisions about resource allocations.

Emera’s reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric, a vertically integrated regulated electric utility in West Central Florida.
- Canadian Electric Utilities, which includes:
 - Nova Scotia Power Inc. (“NSPI”), a vertically integrated regulated electric utility and the primary electricity supplier in Nova Scotia; and
 - Emera Newfoundland & Labrador Holdings Inc. (“ENL”), consisting of two transmission investments related to an 824 megawatt (“MW”) hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador being developed by Nalcor Energy and forecasted to be generating first power in 2019 and full power in 2020. ENL’s two investments are:
 - a 100 per cent investment in NSP Maritime Link Inc. (“NSPML”), which developed the Maritime Link Project, a \$1.6 billion transmission project, including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. This project went in service on January 15, 2018; and
 - a 49.5 per cent investment in the partnership capital of Labrador-Island Link Limited Partnership (“LIL”), a \$3.7 billion electricity transmission project in Newfoundland and Labrador to enable the transmission of Muskrat Falls energy between Labrador and the island of Newfoundland. Construction of the LIL has been completed and Nalcor recognized the first flow of energy from Labrador to Newfoundland in June 2018. Nalcor continues to work towards commissioning the LIL, which it forecasts to be operational in 2020.
- Other Electric Utilities, which includes:
 - Emera Maine, a regulated electric transmission and distribution utility, in the state of Maine. On March 25, 2019, Emera announced an agreement to sell Emera Maine. The transaction is expected to close in late 2019, subject to approval of the Maine Public Utilities Commission (“MPUC”). Refer to note 4 for further details; and
 - Emera (Caribbean) Incorporated (“ECI”), a holding company with regulated electric utilities that include:
 - The Barbados Light & Power Company Limited (“BLPC”), a vertically integrated regulated electric utility on the island of Barbados;
 - Grand Bahama Power Company Limited (“GBPC”), a vertically integrated regulated electric utility on Grand Bahama Island. On September 1, 2019, Grand Bahama Island was struck by Hurricane Dorian, causing significant damage. Refer to note 14 for further details;
 - a 51.9 per cent interest in Dominica Electricity Services Ltd. (“Domlec”), a vertically integrated regulated electric utility on the island of Dominica; and
 - a 19.1 per cent equity interest in St. Lucia Electricity Services Limited (“Lucelec”), a vertically integrated regulated electric utility on the island of St. Lucia.

- Gas Utilities and Infrastructure, which includes:
 - Peoples Gas System (“PGS”), a regulated gas distribution utility operating across Florida;
 - New Mexico Gas Company, Inc. (“NMGC”), a regulated gas distribution utility serving customers in New Mexico;
 - SeaCoast Gas Transmission, LLC (“SeaCoast”), a regulated intrastate natural gas transmission company offering services in Florida;
 - Emera Brunswick Pipeline Company Limited (“Brunswick Pipeline”), a 145-kilometre pipeline delivering re-gasified liquefied natural gas (“LNG”) 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; and
 - a 12.9 per cent interest in Maritimes & Northeast Pipeline (“M&NP”), a 1,400-kilometre pipeline, which transports natural gas throughout markets in Atlantic Canada and the northeastern United States.

Emera’s investments in other energy-related non-regulated companies (included within the Other reportable segment) include the following:

- Emera Energy, which consists of:
 - Emera Energy Services (“EES”), a physical energy business that purchases and sells natural gas and electricity and provides related energy asset management services;
 - Bridgeport Energy, Tiverton Power and Rumford Power (“New England Gas Generating Facilities” or “NEGG”), power plants in the northeastern United States. On March 29, 2019, Emera completed the sale of the NEGG facilities. Refer to note 4 for further details;
 - Bayside Power Limited Partnership (“Bayside Power”), a power plant in Saint John, New Brunswick. On March 5, 2019, the Company sold the Bayside facility. Refer to note 4 for further details;
 - Brooklyn Power Corporation (“Brooklyn Energy”), a power plant in Brooklyn, Nova Scotia; and
 - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC (“Bear Swamp”), a pumped storage hydroelectric facility in northwestern Massachusetts.
- Emera US Finance LP and TECO Finance, Inc. (“TECO Finance”), financing subsidiaries of Emera;
- Emera Utility Services Inc. (“EUS”), a utility services contractor primarily operating in Atlantic Canada. In Q2 2019, Emera entered into an agreement to sell its EUS equipment. The transaction is expected to close in late 2019. EUS ceased operations on September 30, 2019; 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, 2018, except as described in note 2.

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, 2019.

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 provides strong earnings contributions due to a significant portion of the Company's operations being in northeastern North America, where winter is the peak electricity usage season. The third quarter provides strong earnings contributions due to summer being the heaviest electric consumption season in Florida. Certain quarters may also be impacted by weather and the number and severity of storms.

Leases

The Company determines whether a contract contains a lease at inception by evaluating if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

Emera has leases with independent power producers and other utilities with annual requirements to purchase wind and hydro energy over varying contract lengths that are classified as finance leases. These finance leases are not recorded on the Company's Condensed Consolidated Balance Sheets as payments associated with the leases are variable in nature and there are no minimum fixed lease payments. Lease expense associated with these leases is recorded as "Regulated fuel for generation and purchased power" on the Condensed Consolidated Statements of Income.

Operating lease liabilities and right-of-use ("ROU") assets are recognized on the Condensed Consolidated Balance Sheets based on the present value of the future minimum lease payments over the lease term at commencement date. As most of Emera's leases do not provide an implicit rate, the incremental borrowing rate at commencement of the lease is used in determining the present value of future lease payments. Lease expense is recognized on a straight-line basis over the lease term and is recorded as "Operating, maintenance and general" on the Condensed Consolidated Statements of Income.

Where the Company is the lessor, a lease is a sales-type lease if certain criteria are met and the arrangement transfers control of the underlying asset to the lessee. For arrangements where the criteria are met due to the presence of a third-party residual value guarantee, the lease is a direct financing lease.

For direct finance leases, a net investment in the lease is recorded that consists of the sum of the minimum lease payments and residual value (net of estimated executory costs and unearned income). The difference between the gross investment and the cost of the leased item is recorded as unearned income at the inception of the lease. Unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.

For sales-type leases, the accounting is similar to the accounting for direct finance leases, however the difference between the fair value and the carrying value of the leased item is recorded at lease commencement rather than deferred over the term of the lease.

Emera has certain contractual agreements that include lease and non-lease components, which management has elected to account for as a single lease component for all leases.

2. CHANGE IN ACCOUNTING POLICY

The new USGAAP accounting policies that are applicable to, and adopted by the Company in 2019 are described as follows:

Leases

On January 1, 2019, the Company adopted Accounting Standard Updates (“ASU”) 2016-02, *Leases (Topic 842)*, including all related amendments, using the modified retrospective approach. The standard requires lessees to recognize leases on the balance sheet for all leases with a term of longer than twelve months and disclose key information about leasing arrangements.

As permitted by the optional transition method, Emera did not restate comparative financial information in the Company’s condensed consolidated financial statements, did not reassess whether any expired or existing contracts contained leases and carried forward existing lease classifications. Additionally, the Company elected to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under the leasing guidance within ASC Topic 840. The Company elected to use hindsight to determine the lease term for existing leases and elected to not separate lease components from non-lease components for all lessee and lessor arrangements.

Emera has implemented additional processes and controls to facilitate the identification, tracking and reporting of potential leases based on the requirements of the standard. There were no updates to information technology systems as a result of implementation.

The Company’s adoption of this new standard resulted in right-of-use (“ROU”) assets and lease liabilities of approximately \$58 million as of January 1, 2019. The ROU assets and lease liabilities were measured at the present value of remaining lease payments using the Company’s incremental borrowing rate.

There was no impact to opening retained earnings as at January 1, 2019 or the Company’s net income or cash flows for the three and nine months ended September 30, 2019 as a result of the adoption of the standard. There were no significant impacts to Emera’s accounting for lessor arrangements. Refer to note 16 of the financial statements for further detail.

Targeted Improvements to Accounting for Hedging Activities

On January 1, 2019, the Company adopted ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, which amends the hedge accounting recognition and presentation requirements in ASC Topic 815. This standard improves the transparency and understandability of information about an entity’s risk management activities by better aligning the entity’s financial reporting for hedging relationships with those risk management activities and simplifies the application of hedge accounting. The standard will make more financial and nonfinancial hedging strategies eligible for hedge accounting, amends the presentation and disclosure requirements for hedging activities and changes how entities assess hedge effectiveness. There was no impact on the condensed consolidated financial statements as a result of the adoption of this standard.

Cloud Computing

In August 2018, the Financial Accounting Standards Board (“FASB”) issued ASU 2018-15, *Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*. The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. The guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted and can be applied either retrospectively or prospectively. The Company early adopted the standard effective January 1, 2019 and elected to apply the guidance prospectively. There was no material impact on the condensed consolidated financial statements as a result of the adoption of this standard.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs issued by the FASB. The ASUs that have been issued, but that are not yet effective, are consistent with those disclosed in the Company’s 2018 audited consolidated financial statements, with updates noted below.

Measurement of Credit Losses on Financial Instruments

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

4. DISPOSITIONS

Held for sale

Emera Maine

On March 25, 2019, Emera announced the sale of Emera Maine for a total enterprise value of approximately \$1.3 billion USD including cash proceeds of \$959 million USD, transferred debt and a working capital adjustment on close. The transaction is expected to close in late 2019, subject to the approval of the MPUC. All other required regulatory approvals have been received. A material gain on the sale is expected to be recognized in earnings at closing.

Emera Maine's assets and liabilities are classified as held for sale and are measured at the lower of their carrying value or fair value less costs to sell. The measurement did not result in a fair value adjustment. The Company will continue to record depreciation on these assets, through the transaction closing date, as the depreciation continues to be reflected in customer rates, and will be reflected in the carryover basis of the assets when sold. Depreciation and amortization of \$26 million (\$20 million USD) has been recorded on these assets from March 25, 2019, the date they were classified as held for sale to September 30, 2019.

Other

As at September 30, 2019, an immaterial amount of EUS assets were classified as held for sale as the Company has entered into an agreement to sell these assets. This transaction is expected to close in late 2019. EUS ceased operations on September 30, 2019.

Details of the assets and liabilities classified as held for sale are as follows:

As at millions of Canadian dollars		September 30 2019
Regulatory assets	\$	12
Receivables and other current assets		73
Current assets held for sale		85
Property, plant and equipment		1,311
Goodwill		151
Regulatory assets		118
Other long-term assets		54
Long-term assets held for sale		1,634
Total assets held for sale	\$	1,719
Regulatory liabilities	\$	10
Accounts payable and other current liabilities		84
Current liabilities associated with assets held for sale		94
Long-term debt		475
Deferred income taxes		204
Regulatory liabilities		146
Other long-term liabilities		81
Long-term liabilities associated with assets held for sale		906
Total liabilities associated with assets held for sale	\$	1,000

Dispositions

On March 29, 2019, Emera completed the sale of its three NEGG facilities for cash proceeds of \$799 million (\$598 million USD) including working capital adjustments. The NEGG assets were classified as held for sale at December 31, 2018 and the Company ceased depreciation of these assets on November 27, 2018. On March 5, 2019, the Company completed the sale of its Bayside facility for cash proceeds of \$46 million. The NEGG and Bayside facilities were included within the Company's Other reportable segment. An immaterial loss was recognized on these dispositions.

Details of NEGG's assets and liabilities classified as held for sale at December 31, 2018 are as follows:

As at		December 31
millions of Canadian dollars		2018
Receivables and other current assets	\$	40
Inventory		13
Current assets held for sale		53
Property, plant and equipment		777
Long-term assets held for sale		777
Total assets held for sale	\$	830
Accounts payable and other current liabilities	\$	20
Current liabilities associated with assets held for sale		20
Other long-term liabilities		2
Long-term liabilities associated with assets held for sale		2
Total liabilities associated with assets held for sale	\$	22

5. SEGMENT INFORMATION

Emera manages its reportable segments separately due in part to their different operating, regulatory and geographical 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.

Effective January 1, 2019, Emera has revised its reportable segments to align with strategic priorities and internal governance. These new reporting segments align with how the Company assesses financial performance and makes decisions about resource allocations. All comparative segment financial information has been restated with no impact to reported consolidated results.

The five new reportable segments are:

- Florida Electric Utility;
- Canadian Electric Utilities;
- Other Electric Utilities;
- Gas Utilities and Infrastructure; and
- Other

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter- Segment Eliminations	Total
For the three months ended September 30, 2019							
Operating revenues from external customers (1)	\$ 735	\$ 296	\$ 189	\$ 203	\$ (124)	\$ -	\$ 1,299
Inter-segment revenues (1)	3	-	-	6	11	(20)	-
Total operating revenues	738	296	189	209	(113)	(20)	1,299
Depreciation and amortization	112	58	26	28	2	-	226
Interest expense, net	39	36	13	14	81	-	183
Internally allocated interest (2)	-	-	-	4	(4)	-	-
Operating, maintenance and general ("OM&G")	136	88	46	81	29	(13)	367
Net income (loss) attributable to common shareholders	153	33	23	25	(179)	-	55
For the nine months ended September 30, 2019							
Operating revenues from external customers (1)	1,974	1,065	559	797	100	-	4,495
Inter-segment revenues (1)	9	1	-	17	32	(59)	-
Total operating revenues	1,983	1,066	559	814	132	(59)	4,495
Depreciation and amortization	333	171	84	82	8	-	678
Interest expense, net	116	108	39	44	250	-	557
Internally allocated interest (2)	-	-	-	11	(11)	-	-
OM&G	408	230	141	235	103	(41)	1,076
Net income (loss) attributable to common shareholders	339	171	64	132	(236)	-	470
As at September 30, 2019							
Total assets	16,265	6,526	3,116	5,398	1,419	(1,159) ⁽³⁾	31,565

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes the elimination of these transactions would understate property, plant and equipment, OM&G expenses, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.

(2) Segment net income is reported on a basis that includes internally allocated financing costs.

(3) Primarily relates to consolidated deferred tax reclassifications. Deferred tax assets are reclassified and netted with deferred tax liabilities upon consolidation.

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter- Segment Eliminations	Total
For the three months ended September 30, 2018							
Operating revenues from external customers (1)	\$ 773	\$ 310	\$ 206	\$ 206	\$ -	\$ -	\$ 1,495
Inter-segment revenues (1)	2	-	-	10	14	(26)	-
Total operating revenues	775	310	206	216	14	(26)	1,495
Depreciation and amortization	101	56	28	37	14	-	236
Interest expense, net	30	34	12	14	86	-	176
Internally allocated interest (2)	-	-	-	4	(4)	-	-
OM&G	171	64	44	65	40	(14)	370
Net income (loss) attributable to common shareholders	143	36	31	15	(107)	-	118
For the nine months ended September 30, 2018							
Operating revenues from external customers (1)	2,011	1,053	561	761	339	-	4,725
Inter-segment revenues (1)	6	2	-	23	39	(70)	-
Total operating revenues	2,017	1,055	561	784	378	(70)	4,725
Depreciation and amortization	299	163	88	97	40	-	687
Interest expense, net	96	103	35	40	253	-	527
Internally allocated interest (2)	-	-	-	11	(11)	-	-
OM&G	496	204	139	217	130	(47)	1,139
Net income (loss) attributable to common shareholders	298	174	62	93	(148)	-	479
As at December 31, 2018							
Total assets	15,997	6,275	3,094	5,404	2,653	(1,109) ⁽³⁾	32,314

(1) All significant inter-company balances and inter-company transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities that have not been eliminated because management believes the elimination of these transactions would understate property, plant and equipment, OM&G expenses, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.

(2) Segment net income is reported on a basis that includes internally allocated financing costs.

(3) Primarily relates to consolidated deferred tax reclassifications. Deferred tax assets are reclassified and netted with deferred tax liabilities upon consolidation.

6. REVENUE

The following disaggregates the Company's revenue by major source:

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter- Segment Eliminations	Total
For the three months ended September 30, 2019							
Regulated							
Electric Revenue							
Residential	\$ 430	\$ 135	\$ 70	\$ -	\$ -	\$ -	\$ 635
Commercial	212	91	85	-	-	-	388
Industrial	53	52	10	-	-	2	117
Other electric and regulatory deferrals	38	11	5	-	-	(2)	52
Other (1)	5	7	19	-	-	(3)	28
Regulated electric revenue	738	296	189	-	-	(3)	1,220
Gas Revenue							
Residential	-	-	-	75	-	-	75
Commercial	-	-	-	59	-	-	59
Industrial	-	-	-	12	-	-	12
Finance income (2)(3)	-	-	-	15	-	-	15
Other	-	-	-	44	-	(6)	38
Regulated gas revenue	-	-	-	205	-	(6)	199
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	(23)	-	(23)
Energy sales (4)	-	-	-	-	(2)	(1)	(3)
Capacity	-	-	-	-	2	-	2
Other	-	-	-	4	12	(10)	6
Mark-to-market (3)	-	-	-	-	(102)	-	(102)
Non-regulated revenue	-	-	-	4	(113)	(11)	(120)
Total operating revenues	\$ 738	\$ 296	\$ 189	\$ 209	\$ (113)	\$ (20)	\$ 1,299

(1) Other includes rental revenues, which do not represent revenue from contracts with customers.

(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy Canada.

(3) Revenue which does not represent revenues from contracts with customers.

(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter- Segment Eliminations	Total
For the nine months ended September 30, 2019							
Regulated							
Electric Revenue							
Residential	\$ 1,052	\$ 552	\$ 203	\$ -	\$ -	\$ -	\$ 1,807
Commercial	559	298	256	-	-	-	1,113
Industrial	155	160	33	-	-	2	350
Other electric and regulatory deferrals	200	35	12	-	-	(2)	245
Other (1)	17	21	55	-	-	(10)	83
Regulated electric revenue	1,983	1,066	559	-	-	(10)	3,598
Gas Revenue							
Residential	-	-	-	357	-	-	357
Commercial	-	-	-	218	-	-	218
Industrial	-	-	-	37	-	-	37
Finance income (2)(3)	-	-	-	44	-	-	44
Other	-	-	-	146	-	(17)	129
Regulated gas revenue	-	-	-	802	-	(17)	785
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	3	-	3
Energy sales (4)	-	-	-	-	78	(7)	71
Capacity	-	-	-	-	38	-	38
Other	-	-	-	12	30	(25)	17
Mark-to-market (3)	-	-	-	-	(17)	-	(17)
Non-regulated revenue	-	-	-	12	132	(32)	112
Total operating revenues	\$ 1,983	\$ 1,066	\$ 559	\$ 814	\$ 132	\$ (59)	\$ 4,495

(1) Other includes rental revenues, which do not represent revenue from contracts with customers.

(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy Canada.

(3) Revenue which does not represent revenues from contracts with customers.

(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

millions of Canadian dollars	Florida Electric Utility	Canadian Electric Utilities	Other Electric Utilities	Gas Utilities and Infrastructure	Other	Inter- Segment Eliminations	Total
For the three months ended September 30, 2018							
Regulated							
Electric Revenue							
Residential	\$ 431	\$ 139	\$ 71	\$ -	\$ -	\$ -	\$ 641
Commercial	213	95	97	-	-	-	405
Industrial	55	60	14	-	-	-	129
Other electric and regulatory deferrals	69	9	4	-	-	-	82
Other (1)	7	7	20	-	-	(2)	32
Regulated electric revenue	775	310	206	-	-	(2)	1,289
Gas Revenue							
Residential	-	-	-	74	-	-	74
Commercial	-	-	-	56	-	-	56
Industrial	-	-	-	12	-	-	12
Finance income (2)(3)	-	-	-	15	-	-	15
Other	-	-	-	55	-	(10)	45
Regulated gas revenue	-	-	-	212	-	(10)	202
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	6	-	6
Energy sales (4)	-	-	-	-	67	(5)	62
Capacity	-	-	-	-	39	-	39
Other	-	-	-	4	13	(9)	8
Mark-to-market (3)	-	-	-	-	(111)	-	(111)
Non-regulated revenue	-	-	-	4	14	(14)	4
Total operating revenues	\$ 775	\$ 310	\$ 206	\$ 216	\$ 14	\$ (26)	\$ 1,495

For the nine months ended September 30, 2018

Regulated

Electric Revenue

Residential	\$ 1,034	\$ 532	\$ 192	\$ -	\$ -	\$ -	\$ 1,758
Commercial	561	298	261	-	-	-	1,120
Industrial	155	171	35	-	-	-	361
Other electric and regulatory deferrals	251	33	17	-	-	-	301
Other (1)	16	21	55	-	-	(8)	84
Regulated electric revenue	2,017	1,055	560	-	-	(8)	3,624

Gas Revenue

Residential	-	-	-	339	-	-	339
Commercial	-	-	-	211	-	-	211
Industrial	-	-	-	36	-	-	36
Finance income (2)(3)	-	-	-	41	-	-	41
Other	-	-	-	145	-	(23)	122
Regulated gas revenue	-	-	-	772	-	(23)	749

Non-Regulated

Marketing and trading margin (4)	-	-	-	-	73	-	73
Energy sales (4)	-	-	-	-	217	(12)	205
Capacity	-	-	-	-	96	-	96
Other	-	-	1	12	35	(27)	21
Mark-to-market (3)	-	-	-	-	(43)	-	(43)
Non-regulated revenue	-	-	1	12	378	(39)	352
Total operating revenues	\$ 2,017	\$ 1,055	\$ 561	\$ 784	\$ 378	\$ (70)	\$ 4,725

(1) Other includes rental revenues, which do not represent revenue from contracts with customers.

(2) Revenue related to Brunswick Pipeline's service agreement with Repsol Energy Canada.

(3) Revenue which does not represent revenues from contracts with customers.

(4) Includes gains (losses) on settlement of energy related derivatives, which do not represent revenue from contracts with customers.

Remaining Performance Obligations

Remaining performance obligations primarily represent gas transportation contracts, lighting contracts and long-term steam supply arrangements with fixed contract terms. As of September 30, 2019, the aggregate amount of the transaction price allocated to remaining performance obligations was \$341 million (December 31, 2018 – \$370 million). As allowed by the practical expedient in ASC 606, this amount excludes contracts with an original expected length of one year or less and variable amounts for which Emera recognizes revenue at the amount to which it has the right to invoice for services performed. Emera expects to recognize revenue for the remaining performance obligations through 2033.

7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

Investments subject to significant influence consisted of the following:

	Carrying Value		Equity Income for the		Equity Income for the		Percentage
	September 30	as at December 31	three months ended	September 30	nine months ended	September 30	Ownership
millions of Canadian dollars	2019	2018	2019	2018	2019	2018	2019
LIL(1)	\$ 568	\$ 534	\$ 11	\$ 11	\$ 33	31	49.5
NSPML	548	545	9	10	35	40	100.0
M&NP (2)	144	155	5	4	17	17	12.9
Lucelec (2)	41	42	-	1	2	2	19.1
Bear Swamp (3)	-	-	11	13	29	27	50.0
Other Investments	-	40	2	2	2	4	
	\$ 1,301	\$ 1,316	\$ 38	\$ 41	\$ 118	121	

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.9 per cent of the total of units issued. Emera's percentage ownership in LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined upon final costing of all transmission projects related to the Muskrat Falls development, including the LIL, Labrador Transmission Assets and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments.

(2) Although Emera's ownership percentage of these entities is relatively low, it is considered to have significant influence over the operating and financial decisions of these companies through Board representation. Therefore, Emera records its investment in these entities using the equity method.

(3) The investment balance in Bear Swamp is in a credit position primarily as a result of a \$179 million distribution received in 2015. Bear Swamp's credit investment balance of \$145 million (2018 - \$172 million) is recorded in "Other long-term liabilities" on the Condensed Consolidated Balance Sheets.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 23). NSPML's consolidated summarized balance sheet is illustrated as follows:

As at	September 30	December 31
millions of Canadian dollars	2019	2018
Balance Sheet		
Current assets	\$ 95	86
Property, plant and equipment	1,678	1,690
Non-current assets	192	140
Total assets	\$ 1,965	1,916
Current liabilities	\$ 50	21
Long-term debt	1,288	1,288
Non-current liabilities	79	62
Equity	548	545
Total liabilities and equity	\$ 1,965	1,916

8. INCOME TAXES

The income tax provision differs from that computed using the enacted combined Canadian federal and provincial statutory income tax rate for the following reasons:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Income before provision for income taxes	\$ 29	\$ 108	\$ 536	\$ 545
Statutory income tax rate	31%	31%	31%	31%
Income taxes, at statutory income tax rate	9	34	166	169
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	(16)	(10)	(50)	(41)
Foreign tax rate variance	(15)	(17)	(40)	(34)
Amortization of deferred income tax regulatory liabilities	(13)	(7)	(29)	(24)
Tax effect of equity earnings	(3)	(3)	(12)	(13)
Change in treatment of NMGC net operating loss carryforwards	(7)	-	(7)	-
Florida state tax apportionment adjustment	-	(23)	-	(23)
Other	(4)	(7)	(10)	(5)
Income tax expense (recovery)	\$ (49)	\$ (33)	\$ 18	\$ 29
Effective income tax rate	(169)%	(31)%	3%	5%

In Q3 2018, Emera received approval from the Florida Department of Economic Opportunity to change its Florida state tax apportionment factors. This change resulted in the Company recording a tax benefit of approximately \$23 million in 2018 as a result of the remeasurement of certain deferred tax balances.

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, 2018	234.12	\$ 5,816
Conversion of Convertible Debentures	0.03	1
Issuance of common stock (1)	0.88	49
Issued for cash under Purchase Plans at market rate	3.04	153
Discount on shares purchased under Dividend Reinvestment Plan	-	(7)
Options exercised under senior management share option plan	2.53	102
Employee Share Purchase Plan	-	1
Balance, September 30, 2019	240.60	\$ 6,115

(1) As at September 30, 2019, a total of 0.88 million common shares have been issued through Emera's at-the-market equity program ("ATM Program") at an average price of \$56.76 per share for gross proceeds of \$50 million (\$49.4 million net of issuance costs).

On July 11, 2019, Emera established an ATM Program that allows the Company to issue up to \$600 million of common shares to the public from time to time, at the Company's discretion, at the prevailing market price. The ATM Program was established under a prospectus supplement to the Company's short-form base shelf prospectus which expires on July 14, 2021. As at September 30, 2019, an aggregate gross sales limit of \$550 million remains available for issuance under the ATM program.

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	
	2019	2018	2019	2018
Numerator				
Net income attributable to common shareholders	\$ 55.0	\$ 118.1	\$ 470.3	\$ 479.0
Diluted numerator	55.0	118.1	470.3	479.0
Denominator				
Weighted average shares of common stock outstanding	239.5	232.4	237.4	231.1
Weighted average deferred share units outstanding	1.5	1.3	1.5	1.3
Weighted average shares of common stock outstanding – basic	241.0	233.7	238.9	232.4
Stock-based compensation	0.6	0.3	0.6	0.3
Dividend reinvestment plan	0.8	1.1	0.8	1.1
Convertible Debentures	-	0.1	-	0.1
Weighted average shares of common stock outstanding – diluted	242.4	235.2	240.3	233.9
Earnings per common share				
Basic	\$ 0.23	\$ 0.51	\$ 1.97	\$ 2.06
Diluted	\$ 0.23	\$ 0.50	\$ 1.96	\$ 2.05

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, 2019						
Balance, January 1, 2019	\$ 654	\$ (74)	\$ (7)	\$ (1)	\$ (234)	\$ 338
Other comprehensive income (loss) before reclassifications	(242)	48	3	-	-	(191)
Amounts reclassified from accumulated other comprehensive income loss (gain)	-	-	3	-	11	14
Net current period other comprehensive income (loss)	(242)	48	6	-	11	(177)
Balance, September 30, 2019	\$ 412	\$ (26)	\$ (1)	\$ (1)	\$ (223)	\$ 161
For the nine months ended September 30, 2018						
Balance, January 1, 2018 (1)	\$ 30	\$ 48	\$ (3)	\$ 3	\$ (243)	\$ (165)
Other comprehensive income (loss) before reclassifications	218	(41)	5	-	-	182
Amounts reclassified from accumulated other comprehensive income loss (gain)	-	-	(6)	(4)	26	16
Net current period other comprehensive income (loss)	218	(41)	(1)	(4)	26	198
Balance, September 30, 2018	\$ 248	\$ 7	\$ (4)	\$ (1)	\$ (217)	\$ 33

(1) The January 1, 2018 balance of AOCI and Regulatory Assets includes a prior period reclassification of \$37 million in unrecognized pension and post-retirement benefit costs and \$15 million in deferred taxes (\$22 million, net of tax) to be consistent with current year presentation.

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

For the		Three months ended		Nine months ended	
millions of Canadian dollars		September 30		September 30	
		2019	2018	2019	2018
	Affected line item in the Consolidated Financial Statements	Amounts reclassified from AOCI			
Losses (gain) on derivatives recognized as cash flow hedges					
Foreign exchange forwards	Operating revenue – regulated	\$ 1	\$ (1)	\$ 3	\$ (5)
Power and gas swaps	Non-regulated fuel for generation and purchased power	-	1	-	(2)
Total before tax		1	-	3	(7)
	Income tax expense (recovery)	-	-	-	1
Total net of tax		\$ 1	\$ -	\$ 3	\$ (6)
Net change in available-for-sale investments					
	Retained earnings (1)	-	-	-	\$ (4)
Total net of tax		-	-	-	\$ (4)
Net change in unrecognized pension and post-retirement benefit costs					
Actuarial losses (gains)	OM&G	\$ 4	\$ 8	\$ 12	\$ 28
Past service costs (gains)	OM&G	(1)	(1)	(1)	(1)
Amounts reclassified into obligations	Pension and post-retirement liabilities	1	-	1	-
Total before tax		4	7	12	27
	Income tax expense (recovery)	-	-	(1)	(1)
Total net of tax		\$ 4	\$ 7	\$ 11	\$ 26
Total reclassifications out of AOCI, net of tax, for the period		\$ 5	\$ 7	\$ 14	\$ 16

(1) Related to the adoption of ASU 2016-01, Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities.

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;
- interest rate fluctuations on debt securities; and
- share price fluctuations on stock-based compensation.

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 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.

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 NSPI, Emera Maine, NMGC 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. Tampa Electric and PGS have no derivatives related to hedging as a result of a Florida Public Service Commission approved five-year moratorium on hedging of natural gas purchases which ends on December 31, 2022.
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:

As at millions of Canadian dollars	Derivative Assets		Derivative Liabilities	
	September 30 2019	December 31 2018	September 30 2019	December 31 2018
<i>Cash flow hedges</i>				
Foreign exchange forwards	\$ -	\$ -	\$ 1	\$ 5
	-	-	1	5
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	11	71	23	1
Power purchases	22	2	28	1
Natural gas purchases and sales	5	2	8	4
Heavy fuel oil purchases	4	1	10	1
Foreign exchange forwards	8	29	2	-
	50	105	71	7
<i>HFT derivatives</i>				
Power swaps and physical contracts	15	62	16	76
Natural gas swaps, futures, forwards, physical contracts	116	125	373	403
	131	187	389	479
<i>Other derivatives</i>				
Equity derivatives and interest rate swaps	33	1	-	-
	33	1	-	-
Total gross current derivatives	214	293	461	491
Impact of master netting agreements with intent to settle net or simultaneously	(85)	(126)	(85)	(126)
	129	167	376	365
Current	99	148	275	260
Long-term	30	19	101	105
Total derivatives	\$ 129	\$ 167	\$ 376	\$ 365

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:

As at millions of Canadian dollars	Derivative Assets		Derivative Liabilities	
	September 30 2019	December 31 2018	September 30 2019	December 31 2018
Regulatory deferral	\$ 6	\$ 1	\$ 6	\$ 1
HFT derivatives	79	125	79	125
Total impact of master netting agreements with intent to settle net or simultaneously	\$ 85	\$ 126	\$ 85	\$ 126

Cash Flow Hedges

The Company has foreign exchange forwards to hedge the currency risk for revenue streams denominated in foreign currency for Brunswick Pipeline.

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

For the millions of Canadian dollars	Three months ended September 30		
	2019	2018	
	Foreign Exchange Forwards	Power 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)	-	1
Total gains (losses) in net income	\$ (1)	\$ (1)	\$ 1

For the millions of Canadian dollars	Nine months ended September 30		
	2019	2018	
	Foreign Exchange Forwards	Power Swaps	Foreign Exchange Forwards
Realized gain (loss) in non-regulated fuel for generation and purchased power	\$ -	\$ 2	\$ -
Realized gain (loss) in operating revenue – regulated	(3)	-	5
Total gains (losses) in net income	\$ (3)	\$ 2	\$ 5

As at millions of Canadian dollars	September 30			December 31	
	2019	2018		2018	
	Foreign Exchange Forwards	Power Swaps	Foreign Exchange Forwards	Power Swaps	Foreign Exchange Forwards
Total unrealized gain (loss) in AOCI – net of tax	\$ (1)	\$ (1)	\$ (6)		

The Company expects \$1 million of unrealized losses currently in AOCI to be reclassified into net income within the next twelve months, as the underlying hedged transactions settle.

As at September 30, 2019, the Company had the following notional volumes of outstanding derivatives designated as cash flow hedges that are expected to settle as outlined below:

millions	2019	2020
Foreign exchange forwards (USD) sales	\$ 3	\$ 30

Regulatory Deferral

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

For the millions of Canadian dollars	2019					Three months ended September 30 2018
	Commodity swaps and forwards	Foreign exchange forwards	Commodity swaps and forwards	Physical natural gas and biofuel energy purchases and sales	Foreign exchange forwards	
Unrealized gain (loss) in regulatory assets	\$ (25)	\$ 5	\$ (8)	\$ -	\$ (1)	
Unrealized gain (loss) in regulatory liabilities	10	2	35	-	(4)	
Realized (gain) loss in regulatory liabilities	(3)	-	2	-	-	
Realized (gain) loss in inventory (1)	(4)	(1)	(18)	-	(3)	
Realized (gain) loss in regulated fuel for generation and purchased power (2)	1	(1)	(3)	-	(3)	
Total change in derivative instruments	\$ (21)	\$ 5	\$ 8	\$ -	\$ (11)	

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

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

For the millions of Canadian dollars	2019					Nine months ended September 30 2018
	Commodity swaps and forwards	Foreign exchange forwards	Commodity swaps and forwards	Physical natural gas and biofuel energy purchases and sales	Foreign exchange forwards	
Unrealized gain (loss) in regulatory assets	\$ (71)	\$ (2)	\$ (16)	\$ (1)	\$ 2	
Unrealized gain (loss) in regulatory liabilities	4	(6)	76	-	10	
Realized (gain) loss in regulatory liabilities	1	-	(3)	-	-	
Realized (gain) loss in inventory (1)	(28)	(9)	(43)	-	(14)	
Realized (gain) loss in regulated fuel for generation and purchased power (2)	(1)	(6)	(5)	-	(6)	
Total change in derivative instruments	\$ (95)	\$ (23)	\$ 9	\$ (1)	\$ (8)	

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

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

Commodity Swaps and Forwards

As at September 30, 2019, 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	2019	2020-2022
	Purchases	Purchases
Coal (metric tonnes)	-	1
Natural Gas (Mmbtu)	8	23
Heavy fuel oil (bbls)	1	2
Power (MWh)	-	3

Foreign Exchange Swaps and Forwards

As at September 30, 2019, 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:

	2019	2020-2022
Foreign exchange contracts (millions of US dollars)	\$ 43	\$ 276
Weighted average rate	1.2172	1.3199
% of USD requirements	88%	39%

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	
	2019	2018	2019	2018
Power swaps and physical contracts in non-regulated operating revenues	\$ (2)	\$ (1)	- \$	(11)
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	(67)	(104)	180	55
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	1	2	(4)	2
	\$ (68)	\$ (103)	176 \$	46

As at September 30, 2019, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2019	2020	2021	2022	2023
Natural gas purchases (Mmbtu)	255	167	76	56	41
Natural gas sales (Mmbtu)	224	100	19	7	2
Power purchases (MWh)	2	-	-	-	-
Power sales (MWh)	2	-	-	-	-

Other Derivatives

As at September 30, 2019, the Company had equity derivatives in place to manage the cash flow risk associated with forecasted future cash settlements of deferred compensation obligations. The equity derivative hedges the return on 2.3 million shares and extends until March of 2020.

For the three months ended September 30, 2019, the Company had unrealized gains on equity derivatives of \$11 million (2018 – nil) and \$34 million for the nine months ended September 30, 2019 (2018- nil) recorded in Operating, maintenance and general expense in the Condensed Consolidated Statements of Income.

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, 2019, the Company had \$136 million (December 31, 2018 - \$118 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 \$124 million (December 31, 2018 - \$107 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 2019	December 31 2018
Cash collateral provided to others	\$ 91	\$ 103
Cash collateral received from others	7	77

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, 2019, the total fair value of these derivatives, in a liability position, was \$376 million (December 31, 2018 – \$365 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, 2019			
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	\$ -	\$ 8	\$ -	\$ 8
Power purchases	21	-	-	21
Natural gas purchases and sales	-	4	-	4
Heavy fuel oil purchases	3	-	-	3
Foreign exchange forwards	-	8	-	8
	24	20	-	44
<i>HFT derivatives</i>				
Power swaps and physical contracts	4	-	1	5
Natural gas swaps, futures, forwards, physical contracts and related transportation	(3)	34	16	47
	1	34	17	52
<i>Other derivatives</i>				
Equity derivatives and interest rate swap	33	-	-	33
	33	-	-	33
Total assets	58	54	17	129
Liabilities				
<i>Cash flow hedges</i>				
Foreign exchange forwards	-	1	-	1
	-	1	-	1
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	-	20	-	20
Power purchases	27	-	-	27
Heavy fuel oil purchases	2	8	-	10
Natural gas purchases and sales	4	2	-	6
Foreign exchange forwards	-	2	-	2
	33	32	-	65
<i>HFT derivatives</i>				
Power swaps and physical contracts	5	-	1	6
Natural gas swaps, futures, forwards and physical contracts	6	23	275	304
	11	23	276	310
Total liabilities	44	56	276	376
Net assets (liabilities)	\$ 14	\$ (2)	\$ (259)	\$ (247)

As at	December 31, 2018			
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	\$ -	\$ 70	\$ -	\$ 70
Power purchases	2	-	-	2
Natural gas purchases and sales	-	2	-	2
Heavy fuel oil purchases	-	1	-	1
Foreign exchange forwards	-	29	-	29
	2	102	-	104
<i>HFT derivatives</i>				
Power swaps and physical contracts				
	2	2	3	7
Natural gas swaps, futures, forwards, physical contracts and related transportation				
	1	36	18	55
	3	38	21	62
<i>Other derivatives</i>				
Interest rate swap				
	-	1	-	1
	-	1	-	1
Total assets	5	141	21	167
Liabilities				
<i>Cash flow hedges</i>				
Foreign exchange forwards				
	-	5	-	5
	-	5	-	5
<i>Regulatory deferral</i>				
Commodity swaps and forwards				
Coal purchases	-	1	-	1
Power purchases	1	-	-	1
Heavy fuel oil purchases	-	1	-	1
Natural gas purchases and sales	3	-	-	3
	4	2	-	6
<i>HFT derivatives</i>				
Power swaps and physical contracts				
	14	6	1	21
Natural gas swaps, futures, forwards and physical contracts				
	-	28	305	333
	14	34	306	354
Total liabilities	18	41	306	365
Net assets (liabilities)	\$ (13)	\$ 100	\$ (285)	\$ (198)

The change in the fair value of the Level 3 financial assets for the three months ended September 30, 2019 was as follows:

millions of Canadian dollars	<i>HFT Derivatives</i>		
	Power	Natural gas	Total
Balance, beginning of period	\$ 3	\$ 17	\$ 20
Total realized and unrealized gains (losses) included in non-regulated operating revenues	(2)	(1)	(3)
Balance, September 30, 2019	\$ 1	\$ 16	\$ 17

The change in the fair value of the Level 3 financial liabilities for the three months ended September 30, 2019 was as follows:

millions of Canadian dollars	<i>HFT Derivatives</i>		
	Power	Natural gas	Total
Balance, beginning of period	\$ 1	\$ 176	\$ 177
Total realized and unrealized gains (losses) included in non-regulated operating revenues	-	99	99
Balance, September 30, 2019	\$ 1	\$ 275	\$ 276

The change in the fair value of the Level 3 financial assets for the nine months ended September 30, 2019 was as follows:

millions of Canadian dollars	<i>HFT Derivatives</i>		
	Power	Natural gas	Total
Balance, beginning of period	\$ 3	\$ 18	\$ 21
Total realized and unrealized gains (losses) included in non-regulated operating revenues	(2)	(2)	(4)
Balance, September 30, 2019	\$ 1	\$ 16	\$ 17

The change in the fair value of the Level 3 financial liabilities for the nine months ended September 30, 2019 was as follows:

millions of Canadian dollars	<i>HFT Derivatives</i>		
	Power	Natural gas	Total
Balance, beginning of period	\$ 1	\$ 305	\$ 306
Total realized and unrealized gains (losses) included in non-regulated operating revenues	-	(30)	(30)
Balance, September 30, 2019	\$ 1	\$ 275	\$ 276

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 and nine months ended September 30, 2019, there were no transfers between levels.

Significant unobservable inputs used in the fair value measurement of Emera's natural gas and power derivatives include third party-sourced pricing for instruments based on illiquid markets; internally developed correlation factors and basis differentials; own credit risk; and discount rates. Internally developed correlations and basis differentials are reviewed on a quarterly basis based on statistical analysis of the spot markets in the various illiquid term markets. Where possible, Emera also sources multiple broker prices in an effort to evaluate and substantiate these unobservable inputs. Discount rates may include a risk premium for those long-term forward contracts with illiquid future price points to incorporate the inherent uncertainty of these points. Any risk premiums for long-term contracts are evaluated by observing similar industry practices and in discussion with industry peers. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement.

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

As at		September 30, 2019			
millions of Canadian dollars	Fair Value	Valuation Technique	Unobservable Input	Range	Weighted average
Assets					
<i>HFT derivatives – Power swaps and physical contracts</i>	\$ 1	Modelled pricing	Third-party pricing	\$21.72 - \$79.95	\$34.12
			Probability of default	0.01% - 1.14%	0.25%
			Discount rate	0.02% - 6.30%	2.94%
<i>HFT derivatives – Natural gas swaps, futures, forwards, physical contracts</i>	11	Modelled pricing	Third-party pricing	\$1.26 - \$9.61	\$3.04
			Probability of default	0.01% - 5.71%	0.22%
			Discount rate	0.01% - 17.88%	2.19%
	5	Modelled pricing	Third-party pricing	\$1.66 - \$10.92	\$5.38
			Basis adjustment	\$0.07 - \$1.30	\$0.78
			Probability of default	0.01% - 7.72%	0.40%
			Discount rate	0.01% - 4.72%	1.19%
Total assets	\$ 17				
Liabilities					
<i>HFT derivatives – Power swaps and physical contracts</i>	\$ 1	Modelled pricing	Third-party pricing	\$18.70 - \$25.52	\$24.16
			Correlation factor	92.2% - 92.2%	92.20%
			Probability of default	0.01% - 0.01%	0.01%
			Discount rate	0.00% - 0.00%	0.00%
<i>HFT derivatives – Natural gas swaps, futures, forwards and physical contracts</i>	247	Modelled pricing	Third-party pricing	\$1.28 - \$9.61	\$4.68
			Own credit risk	0.01% - 2.31%	0.12%
			Discount rate	0.01% - 15.96%	2.18%
			28	Modelled pricing	Third-party pricing
Basis adjustment	\$0.07 - \$1.30	\$1.08			
Probability of default	0.01% - 7.72%	0.06%			
			Discount rate	0.01% - 4.61%	1.21%
Total liabilities	\$ 276				
Net assets (liabilities)	\$ (259)				

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	Carrying					
millions of Canadian dollars	Amount	Fair Value	Level 1	Level 2	Level 3	Total
September 30, 2019	\$ 14,377	\$ 16,361	\$ -	\$ 15,879	\$ 482	\$ 16,361
December 31, 2018	\$ 15,411	\$ 15,908	\$ -	\$ 14,991	\$ 917	\$ 15,908

The Company has designated \$1.2 billion USD denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations. An after-tax foreign currency loss of \$19 million was recorded in "Other Comprehensive Income – Unrealized gains (losses) on net investment hedges" for the three months ended September 30, 2019 (2018 – \$25 million gain after-tax). An after-tax foreign currency gain of \$48 million was recorded in Other Comprehensive Income for the nine months ended September 30, 2019 (2018 - \$41 million after-tax foreign currency loss).

14. REGULATORY ASSETS AND LIABILITIES

A summary of the Company's regulatory assets and liabilities is provided below. For a detailed description regarding the nature of the Company's regulatory assets and liabilities, refer to note 14 in Emera's 2018 annual audited consolidated financial statements.

As at millions of Canadian dollars	September 30 2019 (1)	December 31 2018
Regulatory assets		
Deferred income tax regulatory assets	\$ 823	\$ 775
Pension and post-retirement medical plan	378	453
Deferrals related to derivative instruments	65	10
Cost-recovery clauses	38	75
Storm restoration regulatory asset	38	32
Environmental remediation	35	31
Stranded cost recovery	27	28
Unamortized defeasance costs	20	26
Demand side management deferral	21	24
Other	74	115
	\$ 1,519	\$ 1,569
Current	\$ 123	\$ 165
Long-term	1,396	1,404
Total regulatory assets	\$ 1,519	\$ 1,569
Regulatory liabilities		
Deferred income tax regulatory liabilities	\$ 1,024	\$ 1,218
Accumulated reserve - cost of removal	910	955
Regulated fuel adjustment mechanism	141	161
Storm reserve	63	76
Deferrals related to derivative instruments	52	116
Cost-recovery clauses	42	30
Self-Insurance fund (note 23)	29	30
Other	4	24
	\$ 2,265	\$ 2,610
Current	\$ 289	\$ 251
Long-term	1,976	2,359
Total regulatory liabilities	\$ 2,265	\$ 2,610

(1) On March 25, 2019, Emera announced the sale of Emera Maine. As at September 30, 2019, Emera Maine's assets and liabilities were classified as held for sale. Refer to note 4 for further details.

Grand Bahama Power Company

On September 1, 2019, Dorian struck Grand Bahama Island as a Category 5 hurricane, with sustained winds of approximately 285 kilometres per hour. The hurricane stalled over the island for several days, causing significant damage to, or destruction of, homes and businesses served by GBPC. GBPC's generation, transmission and distribution assets sustained damage, including the effect of flooding that resulted from storm surge and rain. All 19,000 of GBPC's customers lost power following the storm. The Company's restoration plan is well underway and by September 30, 2019, power was restored to all customers who were able to receive power, or approximately 16,000 customers.

GBPC maintains insurance for its generation facilities and, as with most utilities, its transmission and distribution networks are self-insured. It is currently estimated that restoration costs for GBPC self-insured assets will be approximately \$12 million USD. At September 30, 2019, the Company incurred and recorded \$11 million (\$8 million USD) of this estimated cost. The \$11 million was recorded as a regulatory asset as management anticipates that recovery of these prudently incurred costs through a regulatory process is probable. Management is working with GBPC's insurance companies to assess the damage to its generation assets. It is anticipated that this damage will be covered by insurance with the exception of \$5 million USD, which is GBPC's share of the insurance deductible, and which has not yet been recorded.

At September 30, 2019, GBPC total assets, excluding goodwill, were \$465 million (\$351 million USD) and \$101 million (\$76 million USD) of Emera's goodwill was related to GBPC. The impact of Hurricane Dorian could adversely affect GBPC's future earnings and impairment of some of its assets and goodwill could occur. The outcome cannot be reasonably determined or estimated at this time, therefore no impairment has been recorded in Q3 2019. The Company expects to complete its impairment analysis in Q4 2019.

NSPI

On September 7, 2019, post-tropical storm Dorian struck Nova Scotia, with sustained hurricane force winds causing widespread damage to NSPI's transmission and distribution system. The total cost of the restoration is expected to be approximately \$39 million. At September 30, 2019, \$23 million of this estimated total cost was capitalized to property, plant and equipment, with the remaining \$16 million charged to OM&G expense. There was no overall impact on NSPI earnings as NSPI's increased storm costs were absorbed by some of the excess non-fuel revenues that were recorded to date in 2019. Any excess non-fuel revenues that are available at the end of the fiscal year will be returned to customers through the fuel adjustment mechanism.

Tampa Electric

In Q3 2019, Tampa Electric incurred approximately \$11 million (\$8 million USD) in costs related to Hurricane Dorian. These costs were charged against the utility's storm reserve regulatory liability.

NMGC

On July 17, 2019, the NMPRC approved a rate increase for NMGC effective August 2019, and allowed NMGC to retain tax reform benefits realized from January 1, 2018 to the effective date of the new rates. The new rates are being phased in over two years and are expected to result in an annual revenue increase of approximately \$3 million USD. The deferred income tax regulatory liability of \$11 million (\$8 million USD) recorded at December 31, 2018 to reflect 2018 tax benefits was recognized in revenue in Q2 2019. The NMPRC also approved the utility's proposed weather adjustment mechanism. Beginning in August 2019, the NMPRC approved a change in the treatment of net operating loss carryforwards. As a result of this change, a tax benefit of approximately \$7 million (\$5 million USD) was recognized in earnings in Q3 2019.

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. Intercompany balances and intercompany transactions have been eliminated on consolidation, except for the net profit on certain transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. All material amounts are under normal interest and credit terms.

Significant transactions between Emera and its associated companies are as follows:

- Transactions between NSPI and NSPML related to the Maritime Link assessment are reported in the Condensed Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling \$26 million for the three months ended September 30, 2019 (2018 - \$25 million) and \$80 million for the nine months ended September 30, 2019 (2018 - \$76 million). NSPML is accounted for as an equity investment and therefore, the corresponding earnings related to this revenue are reflected in Income from equity investments.
- Natural gas transportation capacity purchases from M&NP are reported in the Condensed Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled \$16 million for the three months ended September 30, 2019 (2018 - \$6 million) and \$50 million for the nine months ended September 30, 2019 (2018 - \$22 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Condensed Consolidated Balance Sheets as at September 30, 2019 and at December 31, 2018.

16. LEASES

Lessee

The Company has operating leases for buildings, land, telecommunication services, and rail cars. Emera's leases have remaining lease terms of 1 year to 67 years, some of which include options to extend the leases for up to 65 years. These options are included as part of the lease term when it is considered reasonably certain that they will be exercised.

As at millions of Canadian dollars	Classification	September 30 2019
Right-of-use asset	Other long-term assets	\$ 66
Lease liabilities		
Current	Other current liabilities	4
Long-term	Other long-term liabilities	62
Total lease liabilities		\$ 66

The Company has recorded lease expense of \$30 million and \$116 million for the three and nine months ended September 30, 2019, respectively, of which \$28 million for the third quarter and \$111 million for the nine months ended September 30, 2019, relates to variable costs for power generation facility finance leases.

As at September 30, 2019, future minimum lease payments under non-cancellable operating leases for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2019	2020	2021	2022	2023	Thereafter	Total
Minimum lease payments	\$ 3	\$ 7	\$ 7	\$ 7	\$ 7	\$ 109	\$ 140
Less imputed interest							(74)
Total	\$ 3	\$ 7	\$ 7	\$ 7	\$ 7	\$ 109	\$ 66

Additional information related to Emera's leases is as follows:

For the	Nine months ended September 30, 2019	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases (millions of Canadian dollars)	\$	5
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases (millions of Canadian dollars)	\$	15
Weighted average remaining lease term (years)		39
Weighted average discount rate - operating leases		4.05%

Lessor

The Company's net investment in direct finance and sales-type leases relate to Brunswick Pipeline, compressed natural gas ("CNG") stations and heat pumps.

Direct finance and sales-type lease unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease and is recorded as "Operating revenues – Regulated gas" and "Other income (expenses), net" on the Condensed Consolidated Statements of Income.

The Company manages its risk associated with the residual value of the Brunswick Pipeline lease through proper routine maintenance of the asset.

Customers have the option to purchase CNG station assets at any time after year five of the agreements, which is in 2021, by paying a make-whole payment at the date of the purchase based on a targeted internal rate of return or may take possession of the CNG station asset at the end of the lease term for no cost. Customers have the option to purchase heat pumps at the end of the lease term for a nominal fee.

The net investment in direct finance and sales-type leases consisted of the following:

As at	September 30	
millions of Canadian dollars		2019
Total minimum lease payment to be received	\$	1,066
Less: amounts representing estimated executory costs		(192)
Minimum lease payments receivable	\$	874
Estimated residual value of leased property (unguaranteed)		183
Less: unearned finance lease income		(532)
Net investment in direct finance and sales-type leases	\$	525
Principal due within one year (included in "Receivables and other current assets")		18
Net investment in sales-type leases - long-term (included in "Other long-term assets")		33
Net Investment in direct finance leases - long-term	\$	474

As at September 30, 2019, future minimum lease payments to be received for each of the next five years and in aggregate thereafter are as follows:

millions of Canadian dollars	2019	2020	2021	2022	2023	Thereafter	Total
Minimum lease payments to be received	\$ 19	\$ 72	\$ 71	\$ 70	\$ 69	\$ 765	\$ 1,066
Less: executory costs							(192)
Minimum lease payments receivable	\$ 19	\$ 72	\$ 71	\$ 70	\$ 69	\$ 765	\$ 874

17. 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, New Mexico, Barbados, Dominica and Grand Bahama Island. For details of the Company's employee benefit plan, refer to note 19 in Emera's 2018 annual audited consolidated financial statements.

Emera's net periodic benefit cost included the following:

For the millions of Canadian dollars	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Defined benefit pension plans				
Service cost	\$ 12	\$ 13	\$ 36	\$ 38
Non-service cost				
Interest cost	26	24	78	71
Expected return on plan assets	(37)	(34)	(112)	(103)
Current year amortization of:				
Actuarial losses	4	8	12	28
Past service gains	(1)	(1)	(1)	(1)
Regulated asset	5	7	15	19
Settlements and curtailments	-	-	1	1
Total non-service costs	(3)	4	(7)	15
Total defined benefit pension plans	9	17	29	53
Non-pension benefit plans				
Service cost	1	1	3	4
Non-service cost				
Interest cost	4	4	11	10
Expected return on plan assets	-	(1)	(1)	(2)
Current year amortization of:				
Regulated asset	(2)	(1)	(5)	(2)
Total non-service costs	2	2	5	6
Total non-pension benefit plans	3	3	8	10
Total defined benefit plans	\$ 12	\$ 20	\$ 37	\$ 63

Emera's total contributions related to these defined benefit pension plans and non-pension benefit plans for the three months ended September 30, 2019 were \$29 million (2018 – \$13 million), and for the nine months ended September 30, 2019 were \$63 million (2018 – \$67 million). Annual employer contributions for the defined benefit pension plans only, are estimated to be \$53 million for 2019.

18. 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 22 in Emera's 2018 annual audited consolidated financial statements, and below for 2019 short-term debt financing activity.

Recent Financing Activity by Segment

Other

On March 7, 2019, TECO Energy/Finance extended the maturity date of its \$500 million USD credit facility from March 8, 2019 to March 5, 2020. There were no other significant changes in commercial terms from the prior agreement.

19. LONG-TERM DEBT

For details regarding long-term debt, refer to note 24 in Emera's 2018 annual audited consolidated financial statements, and below for significant long-term debt financing activity in 2019.

Recent Financing Activity by Segment

Florida Electric Utilities

On July 24, 2019, Tampa Electric Company ("TEC") completed a \$300 million USD 30-year senior notes issuance. The notes bear interest at a rate of 3.625 per cent and have a maturity date of June 15, 2050.

Canadian Electric Utilities

On August 2, 2019, NSPI repaid a \$95 million debenture upon maturity. The debenture was repaid using its operating credit facility.

On April 4, 2019, NSPI completed a \$400 million Series AB 30-year medium term notes issuance. The notes bear interest at a rate of 3.57 per cent and have a maturity date of April 5, 2049.

Gas Utilities and Infrastructure

On July 31, 2019, New Mexico Gas Intermediate ("NMGI") repaid a \$50 million USD note upon maturity. The note was repaid using cash on hand.

On May 17, 2019, Emera Brunswick Pipeline amended the maturity date of its \$250 million Credit Agreement from February 2022 to May 2023. There were no other material changes in commercial terms.

Other

On June 14, 2019, Emera US Finance LP repaid a \$500 million USD note upon maturity. The note was repaid using proceeds from the sale of the NEGG facilities.

On June 13, 2019, Emera extended the maturity date of its \$900 million revolving credit facility from June 2020 to June 2024. There were no other significant changes in commercial terms from the prior agreement.

20. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at September 30, 2019, contractual commitments (excluding pensions and other post-retirement obligations, convertible debentures, long-term debt and asset retirement obligations) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	2019	2020	2021	2022	2023	Thereafter	Total
Purchased power (1)(2)	\$ 63	\$ 208	\$ 231	\$ 245	\$ 249	\$ 2,496	\$ 3,492
Transportation (3)	140	426	346	307	267	2,955	4,441
Capital projects (4)	305	292	37	11	1	-	646
Fuel, gas supply and storage	196	440	104	4	1	-	745
Long-term service agreements (5)(6)	10	43	30	29	21	124	257
Equity investment commitments (7)	-	-	190	-	-	-	190
Leases and other (8)	10	16	17	16	10	126	195
Demand side management	12	31	37	39	-	-	119
	\$ 736	\$ 1,456	\$ 992	\$ 651	\$ 549	\$ 5,701	\$ 10,085

As noted below, contractual obligations at September 30, 2019 include contractual obligations related to Emera Maine. On completion of the sale of Emera Maine, all of the remaining future contractual obligations will be transferred to the buyer. Refer to note 4 for additional information.

- (1) Annual requirement to purchase electricity production from independent power producers or other utilities over varying contract lengths.
- (2) Includes \$551 million related to Emera Maine (\$4 million in 2019; \$14 million in 2020; \$25 million in 2021; \$32 million in 2022; \$32 million in 2023 and \$444 million thereafter).
- (3) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.
- (4) Includes \$356 million of commitments related to Tampa Electric's solar and Big Bend Power Station modernization projects.
- (5) 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.
- (6) Includes \$26 million related to various long-term service agreements Emera Maine has entered into for IT maintenance and vegetation management (\$4 million in 2019; \$14 million in 2020; \$4 million in 2021; \$2 million in 2022; and \$2 million in 2023).
- (7) Emera has a commitment to make equity contributions to the Labrador Island Link Limited Partnership.
- (8) Includes operating lease agreements for buildings, land, telecommunications services and rail cars, transmission rights and investment commitments.

NSPI has a contractual obligation to pay NSPML for the use of the Maritime Link over approximately 37 years from its January 15, 2018 in-service date. The UARB approved payment for 2019 is \$111 million, which is currently included in NSPI rates. This payment is subject to a \$10 million holdback. On June 14, 2019, NSPML filed an interim assessment application requesting recovery of 2020 costs of approximately \$145 million, subject to a \$10 million holdback, with a decision expected in Q4 2019. NSPI has included the difference of \$34 million in its proposed fuel stability plan filed with the UARB. After 2020, the timing and amounts payable to NSPML will be subject to regulatory filings with the UARB.

Emera has committed to obtain certain transmission rights for Nalcor Energy, if requested, to enable them to transmit energy which is not otherwise used in Newfoundland or Nova Scotia. This energy would be transmitted from Nova Scotia to New England energy markets beginning at first commercial power of the Muskrat Falls hydroelectric generating facility and related transmission assets when Nalcor commences delivery of the Nova Scotia Block, and continuing for 50 years. As transmission rights are contracted, Emera includes the obligations within "Leases and other" in the above table.

B. Legal Proceedings

TECO Guatemala Holdings (“TGH”)

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

On September 23, 2016, TGH filed a request for resubmission to arbitration. A new tribunal was constituted, and the matter has been fully briefed. A hearing was held in March 2019 and a decision is expected from the tribunal in 2020. In addition, TGH has sued Guatemala in Washington, D.C. court to enforce the \$21 million USD owing. Guatemala’s motion to dismiss the enforcement action was denied. On October 1, 2019, the court granted TGH’s motion for summary judgment which will allow TGH to seek collection of the award plus interest when the order is final. 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, 2019, TEC has estimated its financial liability to be \$37 million (\$28 million USD), primarily at PGS. This estimate assumes that other involved PRPs are credit-worthy entities. 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 believed to be currently credit-worthy and are likely to continue to be credit-worthy 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. Other factors that could impact these estimates include 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 base rate proceedings.

Emera Maine

From 2011 to 2016, four separate complaints were filed with the Federal Energy Regulatory Commission (“FERC”) to challenge the base return on equity (“ROE”) under the ISO-New England (“ISO-NE”) Open Access Transmission Tariff (“OATT”).

- Complaint I, filed by a group including the Attorney General of Massachusetts, New England utilities commissions, state public advocates and end users, was remanded to the FERC by the US Court of Appeals in 2017 for further proceedings. No reserve has been made with respect to Complaint I due to uncertainty of the outcome.
- Complaints II and III (the “ENE” and “MA AG II” cases), brought by a group of consumer advocates and by a group of state commissions, state public advocates and end users respectively, have been joined together and are presently pending before the FERC. Emera Maine has recorded a reserve of approximately \$4 million USD for these cases. These reserves 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 based on Emera Maine’s best estimate of the probable outcome.
- Complaint IV was filed by the Eastern Massachusetts Consumer Owned Systems (“EMCOS”). On March 27, 2018, a FERC Administrative Law Judge issued an Initial Decision concluding that the currently-filed base ROE of 10.57 per cent, which with incentive adders may reach a maximum ROE of 11.74 per cent, is not unjust and unreasonable. This decision was appealed to the FERC. No reserve has been made in relation to Complaint IV due to the uncertainty of the final outcome.

On October 16, 2018, the FERC issued an order that addressed all four complaint proceedings. The FERC order proposed a new methodology to set ROEs. Based on the new methodology, the FERC’s preliminary finding was a 10.41 per cent base ROE for the ISO-NE OATT. The FERC has permitted parties to comment on the new methodology and its application to the four pending complaint proceedings. No new or additional reserves have been made with respect to any of the four pending complaints due to uncertainty.

Other Legal Proceedings

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

C. Principal Financial Risks and Uncertainties

Emera believes the following principal financial risks could materially affect the Company in the normal course of business. Risks associated with derivative instruments and fair value measurements are discussed in note 12 and note 13.

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

Foreign Exchange Risk

The Company is exposed to foreign currency exchange rate changes. Emera operates internationally, 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 foreign currency derivative instruments to hedge specific transactions. The Company may enter into foreign exchange forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenues streams and capital expenditures. 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 do not impact net income as they are reported in AOCI.

Liquidity and Capital Market Risk

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, select asset sales, short-term credit facilities, and ongoing access to capital markets. Cash flows generated from the sale of select assets are dependent on the market for the assets, acceptable pricing and the timing of the close of any sales. The Company reasonably expects liquidity sources to exceed capital needs.

Emera's access to capital and cost of borrowing is subject to a number of risk factors including financial market conditions and ratings assigned by credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in property, plant and equipment. Emera is subject to risk with changes in interest rates that could have an adverse effect on the cost of financing. Inability to access cost-effective capital could have a material impact on Emera's ability to fund its growth plan.

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 decrease in a credit rating 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. Emera manages this risk by actively monitoring and managing key financial metrics with the objective of sustaining investment grade credit ratings.

The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to reduce the earnings volatility derived from stock-based compensation, preferred share units and deferred share units.

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. Regulatory ROE will generally follow the direction of interest rates, such that regulatory ROE's are likely to fall in times of reducing interest rates and rise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

Commodity Price Risk

A large portion of the Company's fuel supply comes from international suppliers and is subject to commodity price risk. The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. Fuel contracts may be exposed to broader global conditions, which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable. In addition, the adoption and implementation of fuel adjustment mechanisms in its rate-regulated subsidiaries has further helped manage this risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel costs.

Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the United States and the Caribbean. Any such changes could affect the Company's future earnings, cash flows, and financial position. The value of Emera's existing deferred tax assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws. 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 Company's 2018 audited annual consolidated financial statements, with updates as noted below:

The Company has standby letters of credit and surety bonds in the amount of \$54 million USD (December 31, 2018 - \$67 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one-year term and are renewed annually as required.

Emera Reinsurance Limited has issued a standby letter of credit to secure obligations under reinsurance agreements. The expiry date of this letter of credit was extended to May 2020. This letter of credit is renewed annually. The amount committed as of September 30, 2019 was \$4 million USD (December 31, 2018 - \$6 million USD).

Emera Inc., on behalf of NSPI, has a standby letter of credit to secure obligations under a supplementary retirement plan. The expiry date of this letter of credit was extended to June 2020. The amount committed as at September 30, 2019 was \$52 million (December 31, 2018 - \$49 million).

21. NON-CONTROLLING INTEREST IN SUBSIDIARIES

Non-controlling interest in subsidiaries consisted of the following:

As at millions of Canadian dollars	September 30 2019	December 31 2018
Preferred shares of GBPC (1)	\$ 14	\$ 19
Domlec	21	22
	\$ 35	\$ 41

(1) In June 2019, GBPC redeemed all outstanding preferred shares, replacing them with \$10 million USD debt at 4 per cent and \$10 million USD preferred shares at 6 per cent. The new preferred shares are redeemable by GBPC after June 17, 2021, at \$1,000 Bahamian per share plus accrued and unpaid dividends and are entitled to a 6.0 per cent per annum fixed cumulative preferential dividend to be paid semi-annually, with the first payment scheduled for January 2020.

22. SUPPLEMENTARY INFORMATION TO CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the millions of Canadian dollars	Nine months ended September 30	
	2019	2018
Changes in non-cash working capital:		
Inventory	\$ (28)	\$ (4)
Receivables and other current assets	317	203
Accounts payable	(211)	(54)
Other current liabilities	50	11
Total non-cash working capital	\$ 128	\$ 156

Supplemental disclosure of non-cash activities:

Dividends payable	\$ 159	\$ 148
Common share dividends reinvested	\$ 140	\$ 135
Change in accrued capital expenditures	\$ (14)	\$ (33)
Issuance of depository receipts	\$ -	\$ 22

23. 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 has an investment in a VIE but 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. When the critical milestones were achieved, Nalcor Energy was deemed the primary beneficiary of the asset for financial reporting purposes as it has authority over the majority of the direct activities that are expected to most significantly impact the economic performance of the Maritime Link. Thus, Emera began recording the Maritime Link as an equity investment.

BLPC has established a Self-Insurance Fund (“SIF”), primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission and distribution systems. ECI holds a variable interest in the SIF for which it was determined that ECI was the primary beneficiary and, accordingly, the SIF must be consolidated by ECI. In its determination that ECI controls the SIF, management considered that, in substance, the activities of the SIF are being conducted on behalf of ECI’s subsidiary BLPC and BLPC, alone, obtains the benefits from the SIF’s operations. Additionally, because ECI, through BLPC, has rights to all the benefits of the SIF, it is also exposed to the risks related to the activities of the SIF. 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 “Other long-term assets”, “Restricted cash” and “Regulatory liabilities” on the Condensed Consolidated Balance Sheets. Amounts included in restricted cash represent the cash portion of funds required to be set aside for the BLPC SIF.

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

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

As at	September 30, 2019		December 31, 2018	
	Maximum		Maximum	
millions of Canadian dollars	Total	exposure to	Total	exposure to
Unconsolidated VIEs in which Emera has variable interests	assets	loss	assets	loss
NSPML (equity accounted)	\$ 548	\$ 28	\$ 545	\$ 51

24. 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.

25. SUBSEQUENT EVENTS

These financial statements and notes reflect the Company’s evaluation of events occurring subsequent to the balance sheet date through November 7, 2019, the date the financial statements were issued.