EMERA INCORPORATED

Unaudited Condensed Consolidated

Interim Financial Statements

June 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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Operating revenues				
Regulated electric	**$ 1,209**	$ 1,158	**$ 2,378**	$ 2,335
Regulated gas	**234**	214	**586**	547
Non-regulated	**(65)**	51	**232**	348
Total operating revenues (note 6)	**1,378**	1,423	**3,196**	3,230
Operating expenses				
Regulated fuel for generation and purchased power	**418**	387	**819**	802
Regulated cost of natural gas	**61**	64	**197**	202
Non-regulated fuel for generation and purchased power	**3**	44	**67**	110
Operating, maintenance and general	**343**	377	**709**	769
Provincial, state and municipal taxes	**85**	84	**170**	167
Depreciation and amortization	**228**	228	**452**	451
Total operating expenses	**1,138**	1,184	**2,414**	2,501
Income from operations	**240**	239	**782**	729
Income from equity investments (note 7)	**40**	43	**80**	80
Other income (expenses), net	**6**	(12)	**19**	(21)
Interest expense, net	**185**	176	**374**	351
Income before provision for income taxes	**101**	94	**507**	437
Income tax expense (recovery) (note 8)	**(15)**	(3)	**67**	62
Net income	**116**	97	**440**	375
Non-controlling interest in subsidiaries	**1**	-	**2**	-
Preferred stock dividends	**12**	7	**23**	14
Net income attributable to common shareholders	**$ 103**	$ 90	**$ 415**	$ 361
Weighted average shares of common stock outstanding (in millions) (note 10)				
Basic	**239.2**	232.5	**237.8**	231.8
Diluted	**239.8**	232.9	**238.4**	232.3
Earnings per common share (note 10)				
Basic	**$ 0.43**	$ 0.38	**$ 1.75**	$ 1.56
Diluted	**$ 0.43**	$ 0.38	**$ 1.74**	$ 1.55
Dividends per common share declared	**$ 0.5875**	$ 0.5650	**$ 1.1750**	$ 1.1300

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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Net income	**$ 116**	$ 97	**$ 440**	$ 375
Other comprehensive income (loss), net of tax				
Foreign currency translation adjustment	**(175)**	161	**(338)**	346
Unrealized gains (losses) on net investment hedges (1) (2)	**33**	(30)	**67**	(66)
Cash flow hedges				
Net derivative gains (losses)	**1**	1	**3**	2
Less: reclassification adjustment for losses (gains) included in income (3)	**-**	(1)	**2**	(6)
Net effects of cash flow hedges	**1**	-	**5**	(4)
Unrealized gains (losses) on available-for-sale investment				
Unrealized gain (loss) arising during the period	**-**	1	**-**	-
Less: reclassification adjustment for (gains) losses recognized in income	**-**	-	**-**	(4)
Net unrealized holding gains (losses)	**-**	1	**-**	(4)
Net change in unrecognized pension and post-retirement benefit obligation (4)	**4**	11	**8**	19
Other comprehensive income (loss) (5)	**(137)**	143	**(258)**	291
Comprehensive income (loss)	**(21)**	240	**182**	666
Comprehensive income (loss) attributable to non-controlling interest	**-**	2	**1**	3
Comprehensive income (loss) of Emera Incorporated	**$ (21)**	$ 238	**$ 181**	$ 663

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

(1) Net of tax expense of nil (2018 - $3 million tax recovery) for the three months ended June 30, 2019 and tax expense of nil (2018 – $9 million tax recovery) for the six months ended June 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 June 30, 2019 and tax expense of nil (2018 – $1 million tax recovery) for the six months ended June 30, 2019.

(4) Net of tax expense of nil (2018 - $1 million tax expense) for the three months ended June 30, 2019 and tax expense of $1 million (2018 – $1 million tax expense) for the six months ended June 30, 2019.

(5) Net of tax expense of nil (2018 - $2 million tax recovery) for the three months ended June 30, 2019 and tax expense of $1 million (2018 – $9 million tax recovery) for the six months ended June 30, 2019.

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at millions of Canadian dollars		June 30 2019		December 31 2018
Assets				
Current assets				
Cash and cash equivalents	**$**	**333**	$	316
Restricted cash		**51**		56
Inventory		**442**		474
Derivative instruments (notes 12 and 13)		**90**		148
Regulatory assets (note 14)		**162**		165
Receivables and other current assets		**1,209**		1,620
Assets held for sale (note 4)		**80**		53
		2,367		2,832
Property, plant and equipment, net of accumulated depreciation and amortization of $8,134 and $8,567, respectively		**17,402**		18,712
Other assets				
Deferred income taxes		**168**		175
Derivative instruments (notes 12 and 13)		**25**		19
Regulatory assets (note 14)		**1,348**		1,404
Net investment in direct financing lease (note 16)		**471**		475
Investments subject to significant influence (note 7)		**1,289**		1,316
Goodwill		**5,909**		6,313
Other long-term assets		**282**		291
Assets held for sale (note 4)		**1,599**		777
		11,091		10,770
Total assets	**$**	**30,860**	$	32,314

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited) – Continued

As at millions of Canadian dollars		**June 30 2019**		December 31 2018
Liabilities and Equity				
Current liabilities				
Short-term debt (note 18)	**$**	**1,298**	$	1,186
Current portion of long-term debt		**824**		1,119
Accounts payable		**939**		1,289
Derivative instruments (notes 12 and 13)		**168**		260
Regulatory liabilities (note 14)		**250**		251
Other current liabilities		**356**		428
Liabilities associated with assets held for sale (note 4)		**104**		20
		3,939		4,553
Long-term liabilities				
Long-term debt (note 19)		**13,088**		14,292
Deferred income taxes		**1,079**		1,320
Derivative instruments (notes 12 and 13)		**87**		105
Regulatory liabilities (note 14)		**2,056**		2,359
Pension and post-retirement liabilities (note 17)		**539**		641
Other long-term liabilities		**782**		684
Long-term liabilities associated with assets held for sale (note 4)		**869**		2
		18,500		19,403
Equity				
Common stock (note 9)		**6,010**		5,816
Cumulative preferred stock		**1,004**		1,004
Contributed surplus		**79**		84
Accumulated other comprehensive income (loss) (note 11)		**81**		338
Retained earnings		**1,212**		1,075
Total Emera Incorporated equity		**8,386**		8,317
Non-controlling interest in subsidiaries (note 21)		**35**		41
Total equity		**8,421**		8,358
Total liabilities and equity	**$**	**30,860**	$	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" *"Scott Balfour"*

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

Emera Incorporated
Condensed Consolidated Statements of Cash Flows (Unaudited)

For the millions of Canadian dollars	Six months ended June 30 **2019**	2018
Operating activities		
Net income	**$ 440**	$ 375
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**457**	456
Income from equity investments, net of dividends	**(38)**	(61)
Allowance for equity funds used during construction	**(8)**	(4)
Deferred income taxes, net	**51**	42
Net change in pension and post-retirement liabilities	**(8)**	(8)
Regulated fuel adjustment mechanism	**(1)**	1
Net change in fair value of derivative instruments	**(148)**	(46)
Net change in regulatory assets and liabilities	**(5)**	36
Net change in capitalized transportation capacity	**40**	(20)
Other operating activities, net	**(5)**	(4)
Changes in non-cash working capital (note 22)	**32**	97
Net cash provided by operating activities	**807**	864
Investing activities		
Proceeds from dispositions (note 4)	**860**	-
Additions to property, plant and equipment	**(1,122)**	(960)
Net purchase of investments subject to significant influence, inclusive of acquisition costs	**-**	(41)
Other investing activities	**(2)**	17
Net cash used in investing activities	**(264)**	(984)
Financing activities		
Change in short-term debt, net	**162**	3
Proceeds from short-term debt with maturities greater than 90 days	**-**	129
Proceeds from long-term debt, net of issuance costs	**442**	482
Retirement of long-term debt	**(684)**	(722)
Net borrowings (repayments) under committed credit facilities	**(302)**	20
Issuance of common stock, net of issuance costs	**91**	6
Issuance of preferred stock, net of issuance costs	**-**	292
Dividends on common stock	**(181)**	(166)
Dividends on preferred stock	**(23)**	(14)
Other financing activities	**(20)**	(29)
Net cash (used in) provided by financing activities	**(515)**	1
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**(16)**	15
Net increase (decrease) in cash, cash equivalents, restricted cash and assets held for sale	**12**	(104)
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	**$ 384**	$ 399
Cash, cash equivalents, restricted cash, and assets held for sale consists of:		
Cash	**$ 325**	$ 327
Short-term investments	**7**	3
Restricted cash	**51**	69
Assets held for sale	**1**	-
Cash, cash equivalents, restricted cash, and assets held for sale	**$ 384**	$ 399

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 June 30, 2019							
Balance, March 31, 2019	$ 5,899	$ 1,004	$ 82	$ 217	$ 1,249	$ 40	$ 8,491
Net income of Emera Incorporated	-	-	-	-	115	1	116
Other comprehensive income (loss), net of tax expense of nil	-	-	-	(136)	-	(1)	(137)
Dividends declared on preferred stock (1)	-	-	-	-	(12)	-	(12)
Dividends declared on common stock ($0.5875/share)	-	-	-	-	(140)	-	(140)
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	50	-	-	-	-	-	50
Senior management stock options exercised	61	-	(3)	-	-	-	58
Balance, June 30, 2019	$ 6,010	$ 1,004	$ 79	$ 81	$ 1,212	$ 35	$ 8,421

millions of Canadian dollars	Common Stock	Preferred Stock	Contributed Surplus	AOCI	Retained Earnings	Non-Controlling Interest	Total Equity
For the six months ended June 30, 2019							
Balance, December 31, 2018	$ 5,816	$ 1,004	$ 84	$ 338	$ 1,075	$ 41	$ 8,358
Net income of Emera Incorporated	-	-	-	-	438	2	440
Other comprehensive income (loss), net of tax expense of $1 million	-	-	-	(257)	-	(1)	(258)
Dividends declared on preferred stock (2)	-	-	-	-	(23)	-	(23)
Dividends declared on common stock ($1.1750/share)	-	-	-	-	(278)	-	(278)
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	101	-	-	-	-	-	101
Senior management stock options exercised	93	-	(5)	-	-	-	88
Other	-	-	-	-	-	(2)	(2)
Balance, June 30, 2019	$ 6,010	$ 1,004	$ 79	$ 81	$ 1,212	$ 35	$ 8,421

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

(1) Series A; $0.15970/share, Series B; $0.21150/share, Series C; $0.29506/share, Series E; $0.28125/share, Series F; $0.265625/share and Series H; $0.306250/share

(2) Series A; $0.31940/share, Series B; $0.43210/share, Series C; $0.59012/share, Series E; $0.56250/share, Series F; $0.53125/share and Series H; $0.61250

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 June 30, 2018								
Balance, March 31, 2018	$	5,674$	709$	84$	(17)$	1,039$	39$	7,528
Net income of Emera Incorporated		-	-	-	-	97	-	97
Other comprehensive income (loss), net of tax recovery of $2 million		-	-	-	140	-	2	142
Dividends declared on preferred stock (1)		-	-	-	-	(7)	-	(7)
Dividends declared on common stock ($0.5650/share)		-	-	-	-	(131)	-	(131)
Issuance of preferred shares, net of after-tax issuance costs		-	295	-	-	-	-	295
Common stock issued under purchase plan		50	-	-	-	-	-	50
Acquisition of non-controlling interest of ECI		-	-	(3)	-	-	-	(3)
Other		-	-	1	-	(1)	(1)	(1)
Balance, June 30, 2018	$	5,724$	1,004$	82$	123$	997$	40$	7,970

millions of Canadian dollars		Common Stock	Preferred Stock	Contributed Surplus	AOCI	Retained Earnings	Non-Controlling Interest	Total Equity
For the six months ended June 30, 2018								
Balance, December 31, 2017	$	5,601$	709$	76$	(165)$	891$	92$	7,204
Net income of Emera Incorporated		-	-	-	-	375	-	375
Other comprehensive income (loss), net of tax recovery of $9 million		-	-	-	288	-	3	291
Dividends declared on preferred stock (2)		-	-	-	-	(14)	-	(14)
Dividends declared on common stock ($1.1300/share)		-	-	-	-	(260)	-	(260)
Issuance of preferred shares, net of after-tax issuance costs		-	295	-	-	-	-	295
Common stock issued under purchase plan		100	-	-	-	-	-	100
Acquisition of non-controlling interest of ECI		22	-	5	-	-	(53)	(26)
Other		1	-	1	-	5	(2)	5
Balance, June 30, 2018	$	5,724$	1,004$	82$	123$	997$	40$	7,970

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

(1) Series A; $0.15970/share, Series B; $0.18350/share, Series C; $0.25625/share, Series E; $0.28125/share and Series F; $0.265625/share

(2) Series A; $0.31940/share, Series B; $0.36220/share, Series C; $0.51250/share, Series E; $0.56250/share and Series F; $0.53125/share

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 $1.56 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 complete 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 regulatory approvals. 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;
        - 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, LLC ("M&NP"), a 1,400-kilometre pipeline, which transports natural gas from offshore Nova Scotia to markets in Atlantic Canada and the northeastern United States.

Emera'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 Q3 2019. Refer to note 4; 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 six months ended June 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.

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 United States dollar ("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 certain regulatory approvals including the approval of the Maine Public Utilities Commission. On June 25, 2019, the transaction received approval by the Federal Energy Regulatory Commission and, on July 18, 2019, the Committee on Foreign Investment in the United States concluded its review of the transaction and found no unresolved national security concerns. The applicable provisions of the Hart-Scott-Rodino Antitrust Improvements Act have been satisfied. A material gain on the sale is expected to be recognized at closing.

As a result, 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 $15 million ($11 million USD) has been recorded on these assets from the date they were classified as held for sale to June 30, 2019.

Other

As at June 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. The transaction is expected to close in Q3 2019.

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

As at millions of Canadian dollars		**June 30 2019**
Regulatory assets	$	12
Receivables and other current assets		68
Current assets held for sale		**80**
Property, plant and equipment		1,285
Goodwill		149
Regulatory assets		113
Other long-term assets		52
Long-term assets held for sale		**1,599**
Total assets held for sale	$	**1,679**
Regulatory liabilities	$	11
Accounts payable and other current liabilities		93
Current liabilities associated with assets held for sale		**104**
Long-term debt		443
Deferred income taxes		197
Regulatory liabilities		146
Other long-term liabilities		83
Long-term liabilities associated with assets held for sale		**869**
Total liabilities associated with assets held for sale	$	**973**

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 millions of Canadian dollars		December 31 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 June 30, 2019							
Operating revenues from external customers (1)	$ 694	$ 327	$ 188	$ 238	$ (70)	$ -	$ 1,377
Inter-segment revenues (1)	3	-	-	5	11	(18)	1
Total operating revenues	697	327	188	243	(59)	(18)	1,378
Depreciation and amortization	113	57	29	27	2	-	228
Interest expense, net	38	37	13	15	82	-	185
Internally allocated interest (2)	-	-	-	4	(4)	-	-
Operating, maintenance and general ("OM&G")	139	69	46	75	29	(15)	343
Net income (loss) attributable to common shareholders	125	42	23	40	(127)	-	103
For the six months ended June 30, 2019							
Operating revenues from external customers (1)	1,239	769	370	594	224	-	3,196
Inter-segment revenues (1)	6	1	-	11	21	(39)	-
Total operating revenues	1,245	770	370	605	245	(39)	3,196
Depreciation and amortization	221	113	58	54	6	-	452
Interest expense, net	77	72	26	30	169	-	374
Internally allocated interest (2)	-	-	-	7	(7)	-	-
OM&G	272	142	95	154	74	(28)	709
Net income (loss) attributable to common shareholders	186	138	41	107	(57)	-	415
As at June 30, 2019							
Total assets	15,938	6,454	3,052	5,266	1,355	(1,205) (3)	30,860

(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 June 30, 2018							
Operating revenues from external customers (1)	$ 657	$ 320	$ 182	$ 216	$ 48	$ -	$ 1,423
Inter-segment revenues (1)	2	1	-	6	14	(23)	-
Total operating revenues	659	321	182	222	62	(23)	1,423
Depreciation and amortization	101	54	32	28	13	-	228
Interest expense, net	33	34	12	13	84	-	176
Internally allocated interest (2)	-	-	-	4	(4)	-	-
OM&G	168	62	48	74	46	(21)	377
Net income (loss) attributable to common shareholders	95	48	17	25	(95)	-	90
For the six months ended June 30, 2018							
Operating revenues from external customers (1)	1,238	743	355	555	339	-	3,230
Inter-segment revenues (1)	4	2	-	13	25	(44)	-
Total operating revenues	1,242	745	355	568	364	(44)	3,230
Depreciation and amortization	198	107	60	60	26	-	451
Interest expense, net	66	69	23	26	167	-	351
Internally allocated interest (2)	-	-	-	7	(7)	-	-
OM&G	325	140	95	152	90	(33)	769
Net income (loss) attributable to common shareholders	155	138	31	78	(41)	-	361
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 June 30, 2019							
Regulated							
Electric Revenue							
Residential	$ 348	$ 165	$ 65	$ -	$ -	$ -	**$** 578
Commercial	187	94	91	-	-	-	372
Industrial	56	53	11	-	-	-	120
Other electric and regulatory deferrals	100	8	4	-	-	-	112
Other (1)	6	7	17	-	-	(3)	27
Regulated electric revenue	697	327	188	-	-	(3)	1,209
Gas Revenue							
Residential	-	-	-	93	-	-	93
Commercial	-	-	-	61	-	-	61
Industrial	-	-	-	13	-	-	13
Finance income (2)(3)	-	-	-	15	-	-	15
Other	-	-	-	57	-	(5)	52
Regulated gas revenue	-	-	-	239	-	(5)	234
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	(28)	-	(28)
Energy sales (4)	-	-	-	-	2	(2)	-
Capacity	-	-	-	-	(2)	-	(2)
Other	-	-	-	4	8	(8)	4
Mark-to-market (3)	-	-	-	-	(39)	-	(39)
Non-regulated revenue	-	-	-	4	(59)	(10)	(65)
Total operating revenues	**$ 697**	**$ 327**	**$ 188**	**$ 243**	**$ (59)**	**$ (18)**	**$ 1,378**

(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 six months ended June 30, 2019							
Regulated							
Electric Revenue							
Residential	$ 622	$ 417	$ 133	$ -	$ -	$ -	**$** 1,172
Commercial	347	207	171	-	-	-	725
Industrial	102	108	23	-	-	-	233
Other electric and regulatory deferrals	162	24	7	-	-	-	193
Other (1)	12	14	36	-	-	(7)	55
Regulated electric revenue	1,245	770	370	-	-	(7)	2,378
Gas Revenue							
Residential	-	-	-	282	-	-	282
Commercial	-	-	-	159	-	-	159
Industrial	-	-	-	25	-	-	25
Finance income (2)(3)	-	-	-	29	-	-	29
Other	-	-	-	102	-	(11)	91
Regulated gas revenue	-	-	-	597	-	(11)	586
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	26	-	26
Energy sales (4)	-	-	-	-	80	(6)	74
Capacity	-	-	-	-	36	-	36
Other	-	-	-	8	18	(15)	11
Mark-to-market (3)	-	-	-	-	85	-	85
Non-regulated revenue	-	-	-	8	245	(21)	232
Total operating revenues	**$ 1,245**	**$ 770**	**$ 370**	**$ 605**	**$ 245**	**$ (39)**	**$ 3,196**

(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 June 30, 2018							
Regulated							
Electric Revenue							
Residential	$ 313	$ 157	$ 63	$ -	$ -	$ -	$ 533
Commercial	181	93	86	-	-	-	360
Industrial	52	54	9	-	-	-	115
Other electric and regulatory deferrals	109	10	9	-	-	-	128
Other (1)	4	7	14	-	-	(3)	22
Regulated electric revenue	659	321	181	-	-	(3)	1,158
Gas Revenue							
Residential	-	-	-	86	-	-	86
Commercial	-	-	-	63	-	-	63
Industrial	-	-	-	13	-	-	13
Finance income (2)(3)	-	-	-	13	-	-	13
Other	-	-	-	45	-	(6)	39
Regulated gas revenue	-	-	-	220	-	(6)	214
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	(2)	-	(2)
Energy sales (4)	-	-	-	-	55	(3)	52
Capacity	-	-	-	-	30	-	30
Other	-	-	1	2	12	(11)	4
Mark-to-market (3)	-	-	-	-	(33)	-	(33)
Non-regulated revenue	-	-	1	2	62	(14)	51
Total operating revenues	$ 659	$ 321	$ 182	$ 222	$ 62	$ (23)	$ 1,423
For the six months ended June 30, 2018							
Regulated							
Electric Revenue							
Residential	$ 603	$ 393	$ 121	$ -	$ -	$ -	**$** 1,117
Commercial	348	203	164	-	-	-	715
Industrial	100	111	21	-	-	-	232
Other electric and regulatory deferrals	182	24	13	-	-	-	219
Other (1)	9	14	35	-	-	(6)	52
Regulated electric revenue	1,242	745	354	-	-	(6)	2,335
Gas Revenue							
Residential	-	-	-	265	-	-	265
Commercial	-	-	-	155	-	-	155
Industrial	-	-	-	24	-	-	24
Finance income (2)(3)	-	-	-	26	-	-	26
Other	-	-	-	90	-	(13)	77
Regulated gas revenue	-	-	-	560	-	(13)	547
Non-Regulated							
Marketing and trading margin (4)	-	-	-	-	67	-	67
Energy sales (4)	-	-	-	-	150	(7)	143
Capacity	-	-	-	-	57	-	57
Other	-	-	1	8	22	(18)	13
Mark-to-market (3)	-	-	-	-	68	-	68
Non-regulated revenue	-	-	1	8	364	(25)	348
Total operating revenues	$ 1,242	$ 745	$ 355	$ 568	$ 364	$ (44)	$ 3,230

(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 June 30, 2019, the aggregate amount of the transaction price allocated to remaining performance obligations was $344 million (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 as at June 30	December 31	Equity Income for the three months ended June 30		Equity Income for the six months ended June 30		Percentage of Ownership
millions of Canadian dollars	**2019**	2018	**2019**	2018	**2019**	2018	**2019**
LIL(1)	**$ 556**	$ 534	**$ 11**	$ 10	**$ 22**	$ 20	49.5
NSPML	**549**	545	**12**	15	**26**	30	100.0
M&NP (2)	**144**	155	**6**	7	**12**	13	12.9
Lucelec (2)	**40**	42	**1**	1	**2**	1	19.1
Bear Swamp (3)	**-**	-	**10**	10	**18**	14	50.0
Other Investments	**-**	40	**-**	-	**-**	2	
	$ 1,289	$ 1,316	**$ 40**	$ 43	**$ 80**	$ 80	

(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 Q4 2015. Bear Swamp's credit investment balance of $150 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 millions of Canadian dollars	**June 30 2019**	December 31 2018
Balance Sheet		
Current assets	**$ 93**	$ 86
Property, plant and equipment	**1,672**	1,690
Non-current assets	**177**	140
Total assets	**$ 1,942**	$ 1,916
Current liabilities	**$ 30**	$ 21
Long-term debt	**1,288**	1,288
Non-current liabilities	**75**	62
Equity	**549**	545
Total liabilities and equity	**$ 1,942**	$ 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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Income before provision for income taxes	**$ 101**	$ 94	**$ 507**	$ 437
Statutory income tax rate	**31%**	31%	**31%**	31%
Income taxes, at statutory income tax rate	**31**	29	**157**	135
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(13)**	(10)	**(34)**	(31)
Foreign tax rate variance	**(13)**	(7)	**(25)**	(17)
Amortization of deferred income tax regulatory liabilities	**(11)**	(9)	**(16)**	(17)
Tax effect of equity earnings	**(4)**	(5)	**(9)**	(10)
Other	**(5)**	(1)	**(6)**	2
Income tax expense (recovery)	**$ (15)**	$ (3)	**$ 67**	$ 62
Effective income tax rate	**(15)%**	(3)%	**13%**	14%

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
Issued for cash under Purchase Plans at market rate	2.20	106
Discount on shares purchased under Dividend Reinvestment Plan	-	(5)
Options exercised under senior management share option plan	2.29	93
Balance, June 30, 2019	**238.61**	**$ 6,010**

On July 11, 2019, Emera established an at-the-market equity program ("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 was filed on June 14, 2019 and which expires on July 14, 2021.

No shares have been issued under the ATM Program as of August 9, 2019.

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 June 30 2019	2018	Six months ended June 30 2019	2018
Numerator				
Net income attributable to common shareholders	**$ 103.5**	$ 89.5	**$ 415.3**	$ 360.9
Diluted numerator	**103.5**	89.5	**415.3**	360.9
Denominator				
Weighted average shares of common stock outstanding	**237.7**	231.2	**236.3**	230.5
Weighted average deferred share units outstanding	**1.5**	1.3	**1.5**	1.3
Weighted average shares of common stock outstanding – basic	**239.2**	232.5	**237.8**	231.8
Stock-based compensation	**0.5**	0.3	**0.5**	0.4
Convertible Debentures	**0.1**	0.1	**0.1**	0.1
Weighted average shares of common stock outstanding – diluted	**239.8**	232.9	**238.4**	232.3
Earnings per common share				
Basic	**$ 0.43**	$ 0.38	**$ 1.75**	$ 1.56
Diluted	**$ 0.43**	$ 0.38	**$ 1.74**	$ 1.55

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 six months ended June 30, 2019						
Balance, January 1, 2019	$ 654	$ (74)	$ (7)	$ (1)	$ (234)	$ 338
Other comprehensive income (loss) before reclassifications	(337)	67	3	-	-	(267)
Amounts reclassified from accumulated other comprehensive income loss (gain)	-	-	2	-	8	10
Net current period other comprehensive income (loss)	(337)	67	5	-	8	(257)
Balance, June 30, 2019	$ 317	$ (7)	$ (2)	$ (1)	$ (226)	$ 81
For the six months ended June 30, 2018						
Balance, January 1, 2018 (1)	$ 30	$ 48	$ (3)	$ 3	$ (243)	$ (165)
Other comprehensive income (loss) before reclassifications	343	(66)	2	-	-	279
Amounts reclassified from accumulated other comprehensive income loss (gain)	-	-	(6)	(4)	19	9
Net current period other comprehensive income (loss)	343	(66)	(4)	(4)	19	288
Balance, June 30, 2018	$ 373	$ (18)	$ (7)	$ (1)	$ (224)	$ 123

(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 millions of Canadian dollars	Affected line item in the Consolidated Financial Statements	Three months ended June 30 **2019**	 2018	Six months ended June 30 **2019**	 2018
		Amounts reclassified from AOCI			
Losses (gain) on derivatives recognized as cash flow					
Foreign exchange forwards	Operating revenue – regulated	**-**	(2)	**2**	(4)
Power and gas swaps	Non-regulated fuel for generation and purchased power	**$ -**	$ 1	**$ -**	$ (3)
Total before tax		-	(1)	2	(7)
	Income tax expense (recovery)	**-**	-	**-**	1
Total net of tax		**$ -**	$ (1)	**$ 2**	$ (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					
Actuarial losses (gains)	OM&G	**$ 4**	$ 12	**$ 9**	$ 20
Total before tax		**4**	12	**9**	20
	Income tax expense (recovery)	**-**	(1)	**(1)**	(1)
Total net of tax		**$ 4**	$ 11	**$ 8**	$ 19
Total reclassifications out of AOCI, net of tax, for the period		**$ 4**	$ 10	**$ 10**	$ 9

(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:

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**June 30 2019**	December 31 2018	**June 30 2019**	December 31 2018
Cash flow hedges				
Foreign exchange forwards	**$ -**	$ -	**$ 1**	$ 5
	-	-	**1**	5
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**17**	71	**26**	1
Power purchases	**8**	2	**15**	1
Natural gas purchases and sales	**5**	2	**11**	4
Heavy fuel oil purchases	**17**	1	**-**	1
Foreign exchange forwards	**8**	29	**7**	-
	55	105	**59**	7
HFT derivatives				
Power swaps and physical contracts	**21**	62	**27**	76
Natural gas swaps, futures, forwards, physical contracts	**88**	125	**240**	403
	109	187	**267**	479
Other derivatives				
Equity derivatives and interest rate swaps	**23**	1	**-**	-
	23	1	**-**	-
Total gross current derivatives	**187**	293	**327**	491
Impact of master netting agreements with intent to settle net or simultaneously	**(72)**	(126)	**(72)**	(126)
	115	167	**255**	365
Current	**90**	148	**168**	260
Long-term	**25**	19	**87**	105
Total derivatives	**$ 115**	$ 167	**$ 255**	$ 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:

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**June 30 2019**	December 31 2018	**June 30 2019**	December 31 2018
Regulatory deferral	**$ 7**	$ 1	**$ 7**	$ 1
HFT derivatives	**65**	125	**65**	125
Total impact of master netting agreements with intent to settle net or simultaneously	**$ 72**	$ 126	**$ 72**	$ 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	**2019** **Foreign Exchange Forwards**	Three months ended June 30 Power Swaps	2018 Foreign Exchange Forwards
Realized gain (loss) in non-regulated fuel for generation and purchased power	**$ -**	$ (1)	$ -
Realized gain (loss) in operating revenue – regulated	**-**	-	2
Total gains (losses) in net income	**$ -**	$ (1)	$ 2

For the millions of Canadian dollars	**2019** **Foreign Exchange Forwards**	Six months ended June 30 Power Swaps	2018 Foreign Exchange Forwards
Realized gain (loss) in non-regulated fuel for generation and purchased power	**$ -**	$ 3	$ -
Realized gain (loss) in operating revenue – regulated	**(2)**	-	4
Total gains (losses) in net income	**$ (2)**	$ 3	$ 4

As at millions of Canadian dollars	**June 30 2019** **Foreign Exchange Forwards**	December 31 Power Swaps	2018 Foreign Exchange Forwards
Total unrealized gain (loss) in AOCI – effective portion, 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 June 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	$ 12	$ 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 June 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	**$ (52)**	**$ (6)**	$ 1	$ 1	$ 2
Unrealized gain (loss) in regulatory liabilities	**13**	**(3)**	61	-	8
Realized (gain) loss in regulatory liabilities	**(1)**	**-**	(3)	-	-
Realized (gain) loss in inventory (1)	**(6)**	**(3)**	(12)	-	(6)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**-**	**(3)**	1	-	(2)
Total change in derivative instruments	**$ (46)**	**$ (15)**	$ 48	$ 1	$ 2

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

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

For the millions of Canadian dollars	**2019**		Six months ended June 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	**$ (46)**	**$ (7)**	$ (8)	$ (1)	$ 3
Unrealized gain (loss) in regulatory liabilities	**(6)**	**(8)**	41	-	14
Realized (gain) loss in regulatory liabilities	**4**	**-**	(5)	-	-
Realized (gain) loss in inventory (1)	**(24)**	**(8)**	(25)	-	(11)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**(2)**	**(5)**	(2)	-	(3)
Total change in derivative instruments	**$ (74)**	**$ (28)**	$ 1	$ (1)	$ 3

(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 June 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:

	2019	2020-2022
millions	Purchases	Purchases
Coal (metric tonnes)	1	1
Natural Gas (Mmbtu)	11	6
Heavy fuel oil (bbls)	-	1
Power (MWh)	-	1

Foreign Exchange Swaps and Forwards

As at June 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)	$ 103	$ 256
Weighted average rate	1.2635	1.3194
% of USD requirements	72%	33%

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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Power swaps and physical contracts in non-regulated operating revenues	**$ 2**	$ (1)	**$ 2**	$ (10)
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**43**	22	**247**	159
Power swaps, forwards, futures and physical contracts in non-regulated fuel for generation and purchased power	**(3)**	2	**(5)**	-
	$ 42	$ 23	**$ 244**	$ 149

As at June 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 June 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 June 30, 2019, the Company had unrealized gains on equity derivatives of $9 million (2018 – nil) and $23 million for the six months ended June 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 June 30, 2019, the Company had $144 million (December 31, 2018 - $118 million) in financial assets considered to be past due, which have been outstanding for an average 77 days. The fair value of these financial assets is $132 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	**June 30** **2019**	December 31 2018
Cash collateral provided to others	**$ 46**	$ 103
Cash collateral received from others	**5**	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 June 30, 2019, the total fair value of these derivatives, in a liability position, was $255 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				June 30, 2019
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**$ -**	**$ 12**	**$ -**	**$ 12**
Power purchases	**8**	**-**	**-**	**8**
Natural gas purchases and sales	**-**	**3**	**-**	**3**
Heavy fuel oil purchases	**3**	**14**	**-**	**17**
Foreign exchange forwards	**-**	**8**	**-**	**8**
	11	**37**	**-**	**48**
HFT derivatives				
Power swaps and physical contracts	**2**	**-**	**3**	**5**
Natural gas swaps, futures, forwards, physical contracts and related transportation	**(5)**	**27**	**17**	**39**
	(3)	**27**	**20**	**44**
Other derivatives				
Equity derivatives and interest rate swap	**23**	**-**	**-**	**23**
	23	**-**	**-**	**23**
Total assets	**31**	**64**	**20**	**115**
Liabilities				
Cash flow hedges				
Foreign exchange forwards	**-**	**1**	**-**	**1**
	-	**1**	**-**	**1**
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	**21**	-	**21**
Power purchases	**16**	**-**	**-**	**16**
Natural gas purchases and sales	**6**	**3**	**-**	**9**
Foreign exchange forwards	**-**	**6**	**-**	**6**
	22	**30**	**-**	**52**
HFT derivatives				
Power swaps and physical contracts	**8**	**2**	**1**	**11**
Natural gas swaps, futures, forwards and physical contracts	**3**	**12**	**176**	**191**
	11	**14**	**177**	**202**
Total liabilities	**33**	**45**	**177**	**255**
Net assets (liabilities)	**$ (2)**	**$ 19**	**$ (157)**	**$ (140)**

As at				December 31, 2018
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Regulatory deferral				
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
HFT derivatives				
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
Other derivatives				
Interest rate swap	-	1	-	1
	-	1	-	1
Total assets	5	141	21	167
Liabilities				
Cash flow hedges				
Foreign exchange forwards	-	5	-	5
	-	5	-	5
Regulatory deferral				
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
HFT derivatives				
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 June 30, 2019 was as follows:

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ 2**	**$ 14**	**$ 16**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**1**	**3**	**4**
Balance, June 30, 2019	**$ 3**	**$ 17**	**$ 20**

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

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ 1**	**$ 209**	**$ 210**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**(33)**	**(33)**
Balance, June 30, 2019	**$ 1**	**$ 176**	**$ 177**

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

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ 3**	**$ 18**	**$ 21**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**(1)**	**(1)**
Balance, June 30, 2019	**$ 3**	**$ 17**	**$ 20**

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

	HFT Derivatives		
millions of Canadian dollars	Power	Natural gas	Total
Balance, beginning of period	**$ 1**	**$ 305**	**$ 306**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	**-**	**(129)**	**(129)**
Balance, June 30, 2019	**$ 1**	**$ 176**	**$ 177**

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 six months ended June 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					June 30, 2019
millions of Canadian dollars	Fair Value	Valuation Technique	Unobservable Input	Range	Weighted average
Assets					
HFT derivatives – Power swaps and physical contracts	$ 1	Modelled pricing	Third-party pricing	**$20.70 - $73.20**	**$33.47**
			Probability of default	**0.01% - 3.89%**	**0.32%**
			Discount rate	**0.22% - 7.70%**	**3.14%**
	2	Modelled pricing	Third-party pricing	**$23.84 - $30.71**	**$28.77**
			Probability of default	**0.01% - 0.12%**	**0.11%**
			Discount rate	**0.03% - 0.60%**	**0.03%**
			Correlation factor	**85.41% - 85.41%**	**85.41%**
HFT derivatives – Natural gas swaps, futures, forwards, physical contracts	11	Modelled pricing	Third-party pricing	**$1.57 - $8.94**	**$2.93**
			Probability of default	**0.01% - 4.94%**	**0.38%**
			Discount rate	**0.02% - 22.74%**	**4.17%**
	6	Modelled pricing	Third-party pricing	**$1.91 - $10.25**	**$3.84**
			Basis adjustment	**$0.00 - $1.31**	**$0.34**
			Probability of default	**0.01% - 4.67%**	**0.29%**
			Discount rate	**0.02% - 5.73%**	**1.57%**
Total assets	**$ 20**				
Liabilities					
HFT derivatives – Power swaps and physical contracts	$ 1	Modelled pricing	Third-party pricing	**$18.62 - $30.52**	**$20.90**
			Correlation factor	**85.41% - 85.41%**	**85.41%**
			Probability of default	**0.00% - 0.00%**	**0.00%**
			Discount rate	**0.03% - 1.12%**	**0.85%**
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	166	Modelled pricing	Third-party pricing	**$1.57 - $8.94**	**$3.91**
			Own credit risk	**0.01% - 2.05%**	**0.07%**
			Discount rate	**0.02% - 20.31%**	**2.32%**
	10	Modelled pricing	Third-party pricing	**$1.49 - $10.18**	**$7.41**
			Basis adjustment	**$0.00 - $1.31**	**$0.39**
			Probability of default	**0.00% - 2.00%**	**0.00%**
			Discount rate	**0.02% - 4.80%**	**1.32%**
Total liabilities	**$ 177**				
Net assets (liabilities)	**$ (157)**				

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 millions of Canadian dollars	Carrying Amount	Fair Value	Level 1	Level 2	Level 3	Total
June 30, 2019	**$ 13,912**	**$ 15,394**	**$ -**	**$ 14,928**	**$ 466**	**$ 15,394**
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 gain of $33 million was recorded in “Other Comprehensive Income – Unrealized gains (losses) on net investment hedges” for the three months ended June 30, 2019 (2018 – $30 million loss after-tax). An after-tax foreign currency gain of $67 million was recorded in Other Comprehensive Income for the six months ended June 30, 2019 (2018 - $66 million after-tax foreign currency loss). There was no ineffectiveness for the three and six months ended June 30, 2019 (2018 – nil).

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		**June 30** **2019** (1)		December 31 2018
Regulatory assets				
Deferred income tax regulatory assets	**$**	**797**	$	775
Pension and post-retirement medical plan		**378**		453
Cost-recovery clauses		**77**		75
Deferrals related to derivative instruments		**54**		10
Environmental remediation		**33**		31
Stranded cost recovery		**27**		28
Hurricane Matthew restoration		**25**		28
Unamortized defeasance costs		**22**		26
Demand side management deferral		**22**		24
Storm reserve		**4**		4
Other		**71**		115
	$	**1,510**	$	1,569
Current	**$**	**162**	$	165
Long-term		**1,348**		1,404
Total regulatory assets	**$**	**1,510**	$	1,569
Regulatory liabilities				
Deferred income tax regulatory liabilities	**$**	**1,037**	$	1,218
Accumulated reserve - cost of removal		**917**		955
Regulated fuel adjustment mechanism		**160**		161
Storm reserve		**73**		76
Deferrals related to derivative instruments		**53**		116
Cost-recovery clauses		**32**		30
Self-Insurance fund (note 23)		**29**		30
Other		**5**		24
	$	**2,306**	$	2,610
Current	**$**	**250**	$	251
Long-term		**2,056**		2,359
Total regulatory liabilities	**$**	**2,306**	$	2,610

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

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 will be 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.

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 $27 million for the three months ended June 30, 2019 (2018 - $27 million) and $54 million for the six months ended June 30, 2019 (2018 - $51 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 June 30, 2019 (2018 - $6 million) and $34 million for the six months ended June 30, 2019 (2018 - $16 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Condensed Consolidated Balance Sheets as at June 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		**June 30 2019**
Right-of-use asset	Other long-term assets	**$**	**51**
Lease liabilities			
Current	Other current liabilities		**4**
Long-term	Other long-term liabilities		**47**
Total lease liabilities		**$**	**51**

The Company has recorded lease expense of $35 million and $86 million for the three and six months ended June 30, 2019, respectively, of which $33 million for the three months ended and $83 million for the six months ended June 30, 2019, relates to variable costs for power generation facility finance leases.

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	$ 4	$ 6	$ 6	$ 6	$ 5	$ 82	$ 109
Less imputed interest							(58)
Total	$ 4	$ 6	$ 6	$ 6	$ 5	$ 82	$ 51

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

For the		Six months ended June 30, 2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases (millions of Canadian dollars)	$	4
Weighted average remaining lease term (years)		42
Weighted average discount rate- operating leases		3.98%

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 by monitoring the creditworthiness of the counterparty on a regular basis, maintaining a guarantee with the parent company of the counterparty, and through proper routine maintenance of the asset.

Customers have the option to purchase CNG station assets at any time after 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.

Net investment in direct finance and sales-type leases consist of the following:

As at millions of Canadian dollars		June 30 2019
Total minimum lease payment to be received	$	1,074
Less: amounts representing estimated executory costs		(194)
Minimum lease payments receivable	$	880
Estimated residual value of leased property (unguaranteed)		183
Less: unearned finance lease income		(543)
Net investment in direct finance and sales-type leases	$	520
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")		31
Net Investment in direct finance leases – long-term	$	471

As at June 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	$ 38	$ 72	$ 71	$ 70	$ 68	$ 755	$ 1,074
Less: executory costs							(194)
Minimum lease payments receivable	$ 38	$ 72	$ 71	$ 70	$ 68	$ 755	$ 880

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 June 30		Six months ended June 30	
	2019	2018	**2019**	2018
Defined benefit pension plans				
Service cost	**$ 12**	$ 13	**$ 24**	$ 25
Non-service cost				
Interest cost	**26**	23	**52**	47
Expected return on plan assets	**(38)**	(34)	**(75)**	(69)
Current year amortization of:				
Actuarial losses	**4**	12	**8**	20
Regulated asset	**5**	6	**10**	12
Settlements and curtailments	**1**	-	**1**	-
Special termination benefits	**-**	-	**-**	1
Total non-service costs	**(2)**	7	**(4)**	11
Total defined benefit pension plans	**10**	20	**20**	36
Non-pension benefit plans				
Service cost	**1**	2	**2**	3
Non-service cost				
Interest cost	**3**	3	**7**	6
Expected return on plan assets	**-**	-	**(1)**	(1)
Current year amortization of:				
Past service gains	**-**	(1)	**-**	
Regulated asset	**(1)**	-	**(3)**	(1)
Total non-service costs	**2**	2	**3**	4
Total non-pension benefit plans	**3**	4	**5**	7
Total defined benefit plans	**$ 13**	$ 24	**$ 25**	$ 43

Emera's total contributions related to these defined benefit pension plans and non-pension benefit plans for the three months ended June 30, 2019 were $18 million (2018 – $27 million), and for the six months ended June 30, 2019 were $34 million (2018 – $54 million). Annual employer contributions for the defined benefit pension plans 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 June 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)	$ 129	$ 211	$ 220	$ 223	$ 226	$ 2,139	$ 3,148
Transportation (3)	282	394	309	259	225	2,188	3,657
Capital projects (4)	409	205	46	12	4	17	693
Fuel, gas supply and storage	281	168	52	8	4	-	513
Long-term service agreements (5)(6)	21	43	30	25	20	112	251
Equity investment commitments (7)	-	-	190	-	-	-	190
Leases and other (8)	7	7	9	9	7	90	129
Demand side management	21	1	-	-	-	-	22
	$ 1,150	$ 1,029	$ 856	$ 536	$ 486	$ 4,546	$ 8,603

As noted below, contractual obligations at June 30, 2019 include contractual obligations related to Emera Maine. On completion of the sale of Emera Maine, 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 $182 million related to Emera Maine ($6 million in 2019; $13 million in 2020; $13 million in 2021; $13 million in 2022; $13 million in 2023 and $124 million thereafter).

(3) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines.

(4) Includes $320 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 $30 million related to various long-term service agreements Emera Maine has entered into for IT maintenance and vegetation management ($8 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, and transmission rights.

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, 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. The parties are in the process of filing motions on the matter. 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 June 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 $38 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 December 2019. This letter of credit is renewed annually. The amount committed as of June 30, 2019 was $6 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 June 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		**June 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		Six months ended June 30 **2019**		2018
Changes in non-cash working capital:				
Inventory	**$**	**8**	$	8
Receivables and other current assets		**349**		274
Accounts payable		**(279)**		(112)
Other current liabilities		**(46)**		(73)
Total non-cash working capital	**$**	**32**	$	97
Supplemental disclosure of non-cash activities:				
Common share dividends reinvested	**$**	**96**	$	94
Change in accrued capital expenditures	**$**	**10**	$	(24)
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. In Q2 2014, when the critical milestones were achieved, Nalcor Energy was deemed the primary beneficiary of the asset for financial reporting purposes as they have authority over the majority of the direct activities that are expected to most significantly impact the economic performance of the Maritime Link. 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	**June 30, 2019**		December 31, 2018	
millions of Canadian dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 549**	**$ 45**	$ 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 August 9, 2019, the date the financial statements were issued.