EMERA INCORPORATED

Unaudited Condensed Consolidated

Interim Financial Statements

June 30, 2024 and 2023

Emera Incorporated
Condensed Consolidated Statements of Income (Unaudited)

For the millions of dollars (except per share amounts)	Three months ended June 30 2024	 2023	Six months ended June 30 2024	 2023
Operating revenues				
Regulated electric	**$ 1,482**	$ 1,373	**$ 2,897**	$ 2,735
Regulated gas	**320**	277	**843**	843
Non-regulated	**(185)**	(232)	**(105)**	273
Total operating revenues (note 5)	**1,617**	1,418	**3,635**	3,851
Operating expenses				
Regulated fuel for generation and purchased power	**491**	396	**1,003**	871
Regulated cost of natural gas	**56**	58	**236**	334
Operating, maintenance and general expenses ("OM&G")	**483**	471	**983**	901
Provincial, state and municipal taxes	**109**	107	**215**	209
Depreciation and amortization	**290**	263	**573**	519
Total operating expenses	**1,429**	1,295	**3,010**	2,834
Income from operations	**188**	123	**625**	1,017
Income from equity investments (note 7)	**28**	36	**62**	71
Other income, net (note 8)	**190**	57	**218**	92
Interest expense, net (note 9)	**238**	223	**484**	449
Income (loss) before provision for income taxes	**168**	(7)	**421**	731
Income tax expense (recovery) (note 10)	**21**	(51)	**49**	111
Net income	**147**	44	**372**	620
Preferred stock dividends	**18**	16	**36**	32
Net income attributable to common shareholders	**$ 129**	$ 28	**$ 336**	$ 588
Weighted average shares of common stock outstanding (in millions) (note 12)				
Basic	**287.3**	272.3	**286.2**	271.5
Diluted	**287.4**	272.6	**286.3**	271.8
Earnings per common share (note 12)				
Basic	**$ 0.45**	$ 0.10	**$ 1.17**	$ 2.17
Diluted	**$ 0.45**	$ 0.10	**$ 1.17**	$ 2.16
Dividends per common share declared	**$ 0.7175**	$ 0.6900	**$ 1.4350**	$ 1.3800

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

Emera Incorporated
Condensed Consolidated Statements of Comprehensive Income (Unaudited)

For the millions of dollars	Three months ended June 30 **2024**	 2023	Six months ended June 30 **2024**	 2023
Net income	**$ 147**	$ 44	**$ 372**	$ 620
Other comprehensive income (loss) ("OCI"), net of tax				
Foreign currency translation adjustment (1)	**121**	(250)	**405**	(247)
Unrealized (losses) gains on net investment hedges (2)	**(16)**	35	**(55)**	36
Cash flow hedges – net of reclassification adjustment for gains included in income	**-**	1	**(1)**	-
Unrealized gains on available-for-sale investment	**-**	-	**1**	-
Net change in unrecognized pension and post-retirement benefit obligation	**-**	(1)	**1**	(5)
OCI (3)	**$ 105**	$ (215)	**$ 351**	$ (216)
Comprehensive income (loss) of Emera Incorporated	**$ 252**	$ (171)	**$ 723**	$ 404

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

(1) Net of tax expense of $1 million (2023 – $3 million recovery) for the three months ended June 30, 2024 and tax expense of $5 million (2023 – $7 million recovery) for the six months ended June 30, 2024.
(2) The Company has designated $1.2 billion United States dollar ("USD") denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations.
(3) Net of tax expense of $1 million (2023 – $3 million recovery) for the three months ended June 30, 2024 and tax expense of $5 million (2023 – $7 million recovery) for the six months ended June 30, 2024.

Emera Incorporated
Condensed Consolidated Balance Sheets (Unaudited)

As at millions of dollars		June 30 2024		December 31 2023
Assets				
Current assets				
Cash and cash equivalents	**$**	**348**	$	567
Restricted cash		**33**		21
Inventory		**791**		790
Derivative instruments (notes 14 and 15)		**119**		174
Regulatory assets (note 6)		**187**		339
Receivables and other current assets (note 17)		**1,745**		1,817
		3,223		3,708
Property, plant and equipment ("PP&E"), net of accumulated depreciation and amortization of $10,558 and $9,994, respectively		**25,855**		24,376
Other assets				
Deferred income taxes (note 10)		**208**		208
Derivative instruments (notes 14 and 15)		**43**		66
Regulatory assets (note 6)		**2,619**		2,766
Net investment in direct finance and sales type leases		**613**		621
Investments subject to significant influence (note 7)		**647**		1,402
Goodwill		**6,075**		5,871
Other long-term assets		**501**		462
		10,706		11,396
Total assets	**$**	**39,784**	$	39,480
Liabilities and Equity				
Current liabilities				
Short-term debt (note 19)	**$**	**946**	$	1,433
Current portion of long-term debt (note 20)		**699**		676
Accounts payable		**1,378**		1,454
Derivative instruments (notes 14 and 15)		**397**		386
Regulatory liabilities (note 6)		**210**		168
Other current liabilities		**437**		427
		4,067		4,544
Long-term liabilities				
Long-term debt (note 20)		**17,903**		17,689
Deferred income taxes (note 10)		**2,329**		2,352
Derivative instruments (notes 14 and 15)		**84**		118
Regulatory liabilities (note 6)		**1,713**		1,604
Pension and post-retirement liabilities (note 18)		**261**		265
Other long-term liabilities (note 7)		**866**		820
		23,156		22,848
Equity				
Common stock (note 11)		**8,657**		8,462
Cumulative preferred stock		**1,422**		1,422
Contributed surplus		**83**		82
Accumulated other comprehensive income ("AOCI') (note 13)		**656**		305
Retained earnings		**1,729**		1,803
Total Emera Incorporated equity		**12,547**		12,074
Non-controlling interest in subsidiaries		**14**		14
Total equity		**12,561**		12,088
Total liabilities and equity	**$**	**39,784**	$	39,480

Commitments and contingencies (note 21)

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

Approved on behalf of the Board of Directors

"M. Jacqueline Sheppard"
Chair of the Board

"Scott Balfour"
President and Chief Executive Officer

Emera Incorporated
Condensed Consolidated Statements of Cash Flows (Unaudited)

For the millions of dollars	Six months ended June 30 **2024**	2023
Operating activities		
Net income	**$ 372**	$ 620
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**579**	522
Income from equity investments, net of dividends	**5**	(20)
Allowance for funds used during construction ("AFUDC") – equity	**(21)**	(17)
Deferred income taxes, net	**31**	93
Net change in pension and post-retirement liabilities	**(29)**	(35)
Fuel adjustment mechanism ("FAM")	**83**	10
Net change in fair value ("FV") of derivative instruments	**97**	(601)
Net change in regulatory assets and liabilities	**210**	160
Net change in capitalized transportation capacity	**91**	378
Gain on sale, excluding transaction costs	**(191)**	-
Other operating activities, net	**17**	53
Changes in non-cash working capital (note 22)	**(51)**	(212)
Net cash provided by operating activities	**1,193**	951
Investing activities		
Additions to PP&E	**(1,347)**	(1,351)
Proceeds from disposal of investment subject to significant influence	**927**	-
Other investing activities	**5**	8
Net cash used in investing activities	**(415)**	(1,343)
Financing activities		
Change in short-term debt, net	**(575)**	172
Proceeds from long-term debt, net of issuance costs	**1,342**	537
Retirement of long-term debt	**(464)**	(105)
Net (repayments) proceeds under committed credit facilities	**(1,043)**	55
Issuance of common stock, net of issuance costs	**50**	19
Dividends on common stock	**(267)**	(235)
Dividends on preferred stock	**(36)**	(32)
Other financing activities	**(5)**	(11)
Net cash (used in) provided by financing activities	**(998)**	400
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**13**	(5)
Net (decrease) increase in cash, cash equivalents, and restricted cash	**(207)**	3
Cash, cash equivalents and restricted cash, beginning of period	**588**	332
Cash, cash equivalents and restricted cash, end of period	**$ 381**	$ 335
Cash, cash equivalents, and restricted cash consists of:		
Cash	**$ 337**	$ 303
Short-term investments	**11**	10
Restricted cash	**33**	22
Cash, cash equivalents and restricted cash	**$ 381**	$ 335

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

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

millions of dollars	Common Stock	Preferred Stock	Contributed Surplus	AOCI	Retained Earnings	Non-Controlling Interest	Total Equity
For the three months ended June 30, 2024							
Balance, March 31, 2024	**$ 8,565**	**$ 1,422**	**$ 82**	**$ 551**	**$ 1,806**	**$ 14**	**$ 12,440**
Net income of Emera Incorporated	**-**	**-**	**-**	**-**	**147**	**-**	**147**
OCI, net of tax expense of $1 million	**-**	**-**	**-**	**105**	**-**	**-**	**105**
Dividends declared on preferred stock (1)	**-**	**-**	**-**	**-**	**(18)**	**-**	**(18)**
Dividends declared on common stock ($0.7175/share)	**-**	**-**	**-**	**-**	**(206)**	**-**	**(206)**
Issued under the Dividend Reinvestment Program ("DRIP"), net of discounts	**72**	**-**	**-**	**-**	**-**	**-**	**72**
Issuance of common stock under the at-the-market ("ATM") program, net of after-tax issuance costs	**11**	**-**	**-**	**-**	**-**	**-**	**11**
Senior management stock options exercised and Employee Common Share Purchase Plan ("ECSPP")	**9**	**-**	**1**	**-**	**-**	**-**	**10**
Balance, June 30, 2024	**$ 8,657**	**$ 1,422**	**$ 83**	**$ 656**	**$ 1,729**	**$ 14**	**$ 12,561**

For the six months ended June 30, 2024							
Balance, December 31, 2023	**$ 8,462**	**$ 1,422**	**$ 82**	**$ 305**	**$ 1,803**	**$ 14**	**$ 12,088**
Net income of Emera Incorporated	**-**	**-**	**-**	**-**	**372**	**-**	**372**
OCI, net of tax expense of $5 million	**-**	**-**	**-**	**351**	**-**	**-**	**351**
Dividends declared on preferred stock (2)	**-**	**-**	**-**	**-**	**(36)**	**-**	**(36)**
Dividends declared on common stock ($1.4350/share)	**-**	**-**	**-**	**-**	**(410)**	**-**	**(410)**
Issued under the DRIP, net of discounts	**142**	**-**	**-**	**-**	**-**	**-**	**142**
Issuance of common stock under ATM program, net of after-tax issuance costs	**35**	**-**	**-**	**-**	**-**	**-**	**35**
Senior management stock options exercised and ECSPP	**18**	**-**	**1**	**-**	**-**	**-**	**19**
Balance, June 30, 2024	**$ 8,657**	**$ 1,422**	**$ 83**	**$ 656**	**$ 1,729**	**$ 14**	**$ 12,561**

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

(1) Series A; $0.1364/share, Series B; $0.4242/share, Series C; $0.4021/share, Series E; $0.2813/share, Series F; $0.2626/share; Series H; $0.3953/share; Series J; $0.2656/share and Series L; $0.2875/share
(2) Series A; $0.2728/share, Series B; $0.8650/share, Series C; $0.8043/share, Series E; $0.5625/share, Series F; $0.5253/share; Series H; $0.7905/share; Series J; $0.5313/share and Series L; $0.5750/share

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

millions of dollars	Common Stock	Preferred Stock	Contributed Surplus	AOCI	Retained Earnings	Non-Controlling Interest	Total Equity
For the three months ended June 30, 2023							
Balance, March 31, 2023	$ 7,839	$ 1,422	$ 81	$ 577	$ 1,958	$ 14	$ 11,891
Net income of Emera Incorporated	-	-	-	-	44	-	44
OCI, net of tax recovery of $3 million	-	-	-	(215)	-	-	(215)
Dividends declared on preferred stock (1)	-	-	-	-	(16)	-	(16)
Dividends declared on common stock ($0.6900/share)	-	-	-	-	(188)	-	(188)
Issued under the DRIP, net of discounts	70	-	-	-	-	-	70
Senior management stock options exercised and ECSPP	13	-	-	-	-	-	13
Balance, June 30, 2023	$ 7,922	$ 1,422	$ 81	$ 362	$ 1,798	$ 14	$ 11,599
For the six months ended June 30, 2023							
Balance, December 31, 2022	$ 7,762	$ 1,422	$ 81	$ 578	$ 1,584	$ 14	$ 11,441
Net income of Emera Incorporated	-	-	-	-	620	-	620
OCI, net of tax recovery of $7 million	-	-	-	(216)	-	-	(216)
Dividends declared on preferred stock (2)	-	-	-	-	(32)	-	(32)
Dividends declared on common stock ($1.3800/share)	-	-	-	-	(374)	-	(374)
Issued under the DRIP, net of discount	139	-	-	-	-	-	139
Senior management stock options exercised and ECSPP	21	-	-	-	-	-	21
Balance, June 30, 2023	$ 7,922	$ 1,422	$ 81	$ 362	$ 1,798	$ 14	$ 11,599

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

(1) Series A; $0.1364/share, Series B; $0.3777/share, Series C; $0.2951/share, Series E; $0.2813/share, Series F; $0.2626/share; Series H; $0.3063/share; Series J; $0.2656/share and Series L; $0.2875/share
(2) Series A; $0.2728/share, Series B; $0.7347/share, Series C; $0.5901/share, Series E; $0.5625/share, Series F; $0.5253/share; Series H; $0.6125/share; Series J; $0.5313/share and Series L; $0.5750/share

Emera Incorporated
Notes to the Condensed Consolidated Interim Financial Statements (Unaudited)
As at June 30, 2024 and 2023

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

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

At June 30, 2024, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric ("TEC"), 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
    - a 100 per cent equity interest in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.8 billion, including AFUDC, transmission project between the island of Newfoundland and Nova Scotia.

  On June 4, 2024, Emera completed the sale of its 31.1 per cent indirect minority equity interest in the Labrador Island Link Partnership ("LIL"), which was previously included in the Canadian Electric Utilities segment. For further details, refer to note 3.

- Gas Utilities and Infrastructure, which includes:
    - Peoples Gas System, Inc. ("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. On August 5, 2024, Emera announced an agreement to sell NMGC. The transaction is expected to close in late 2025, subject to certain approvals, including approval by the New Mexico Public Regulation Commission ("NMPRC"). For more information on the pending transaction, refer to note 3;
    - Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline"), a 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick to the United States border under a 25-year firm service agreement with Repsol Energy North America Canada Partnership ("Repsol Energy"), which expires in 2034;
    - SeaCoast Gas Transmission, LLC ("SeaCoast"), a regulated intrastate natural gas transmission company offering services in Florida; and
    - a 12.9 per cent equity interest in Maritimes & Northeast Pipeline ("M&NP"), a 1,400-kilometre pipeline, that transports natural gas throughout markets in Atlantic Canada and the northeastern United States.

- Other Electric Utilities, which includes 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; and
    - a 19.5 per cent equity interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated regulated electric utility on the island of St. Lucia.

- Emera's other segment includes investments in energy-related non-regulated companies that are below the required threshold for reporting as separate segments and corporate expense and revenue items that are not directly allocated to the operations of Emera's subsidiaries and investments. This includes:
  - 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;
    - Brooklyn Power Corporation ("Brooklyn Energy"), a 30 MW biomass co-generation electricity facility in Brooklyn, Nova Scotia; and
    - a 50.0 per cent joint venture interest in Bear Swamp Power Company LLC ("Bear Swamp"), a 660 MW pumped storage hydroelectric facility in northwestern Massachusetts.
  - Emera US Finance LP ("Emera Finance"), EUSHI Finance, Inc., and TECO Finance, Inc. ("TECO Finance"), financing subsidiaries of Emera;
  - Block Energy LLC, a wholly owned technology company focused on finding ways to deliver renewable and resilient energy to customers;
  - Emera US Holdings Inc., a wholly owned holding company for certain of Emera's assets located in the United States; 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, 2023.

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, 2024.

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

Use of Management Estimates

The preparation of unaudited condensed consolidated interim 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. Significant areas requiring use of management estimates relate to rate-regulated assets and liabilities, accumulated reserve for cost of removal, pension and post-retirement benefits, unbilled revenue, useful lives for depreciable assets, goodwill and long-lived assets impairment assessments, income taxes, asset retirement obligations, and valuation of financial instruments. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current and expected 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. There were no material changes in the nature of the Company's critical accounting estimates from those disclosed in Emera's 2023 annual audited consolidated financial statements.

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 during 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.

2. FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all Accounting Standard Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by the FASB, but as allowed, have not yet been adopted by Emera. Any ASUs not included below were assessed and determined to be either not applicable to the Company or to have an insignificant impact on the consolidated financial statements.

Improvements to Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The standard enhances the transparency, decision usefulness and effectiveness of income tax disclosures by requiring consistent categories and greater disaggregation of information in the reconciliation of income taxes computed using the enacted statutory income tax rate to the actual income tax provision and effective income tax rate, as well as the disaggregation of income taxes paid (refunded) by jurisdiction. The standard also requires disclosure of income (loss) before provision for income taxes and income tax expense (recovery) in accordance with U.S. Securities and Exchange Commission Regulation S-X 210.4-08(h), Rules of General Application – General Notes to Financial Statements: Income Tax Expense, and the removal of disclosures no longer considered cost beneficial or relevant. The guidance will be effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted. The standard will be applied on a prospective basis, with retrospective application permitted. The Company is currently evaluating the impact of adoption of the standard on its consolidated financial statements disclosures.

Improvements to Reportable Segment Disclosures

In November 2023, the FASB issued ASU 2023-07, Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures. The change in the standard improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The changes improve financial reporting by requiring disclosure of incremental segment information on an annual and interim basis for all public entities to enable investors to develop more decision-useful financial analyses. The guidance will be effective for annual reporting periods beginning after December 15, 2023, and for interim periods beginning after December 15, 2024. Early adoption is permitted. The standard will be applied retrospectively. The Company does not expect a material impact on its consolidated financial statements disclosures as a result of adoption of the standard.

3. DISPOSITIONS

Pending Sale of NMGC

On August 5, 2024, Emera announced an agreement to sell its indirect wholly owned subsidiary NMGC for a total enterprise value of approximately $1.3 billion USD, consisting of cash proceeds and the transfer of debt and customary closing adjustments. The transaction is expected to close in late 2025, subject to certain approvals, including approval by the NMPRC.

As at June 30, 2024, the held-for-sale ("HFS") criteria were not met and therefore NMGC remained classified as held-and-used as of the balance sheet date. During the subsequent event period, the HFS criteria were met, and therefore the assets and liabilities will be reclassified as HFS in Emera's Q3 2024 financial statements.

As the transaction proceeds will be lower than the carrying amount of the assets and liabilities being sold, Emera assessed the NMGC reporting unit for goodwill impairment by comparing the fair value of expected transaction proceeds to the carrying value, including goodwill of $366 million USD ("carrying amount"). The goodwill of the reporting unit was determined to be impaired. At the time of transaction agreement, the non-cash goodwill impairment loss was estimated to be approximately $70 million, after tax. In Q3 2024, Emera will record a non-cash goodwill impairment which will be measured at the lower of carrying amount and fair value at that point in time. The Company may take future non-cash goodwill impairments as a result of continued investments in the business and the length of time until transaction close, including transaction costs.

Sale of LIL Equity Interest

On June 4, 2024, Emera completed the sale of its 31.1 per cent indirect minority equity interest in the LIL for a total transaction value of $1.2 billion, including cash proceeds of $957 million and $235 million for assuming Emera's contractual obligation to fund the remaining initial capital investment, which represents additional LIL equity interest for the acquirer. Cash proceeds from the sale in the amount of $30 million is held in escrow pending finalization of certain agreements with the LIL general partner. The escrow proceeds receivable is held at fair value and included in the gain on sale, after transaction costs. As of June 30, 2024, the estimated fair value of the escrow proceeds receivable is $25 million. A gain on sale, after transaction costs, of $182 million, ($107 million, after tax and transaction costs), was recognized in "Other Income, net" on the Condensed Consolidated Statements of Income and included in the Other segment.

4. 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.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the three months ended June 30, 2024							
Operating revenues from external customers (1)	$ 918	$ 423	$ 324	$ 142	$ (190)	$ -	$ 1,617
Inter-segment revenues (1)	2	-	4	-	3	(9)	-
Total operating revenues	920	423	328	142	(187)	(9)	1,617
Regulated fuel for generation and purchased power	228	194	-	74	-	(5)	491
Regulated cost of natural gas	-	-	56	-	-	-	56
OM&G	204	95	114	37	40	(7)	483
Provincial, state and municipal taxes	71	12	25	1	-	-	109
Depreciation and amortization	155	69	45	19	2	-	290
Income (loss) from equity investments	-	25	5	1	(3)	-	28
Other income, net	14	7	5	1	166	(3)	190
Interest expense, net (2)	64	42	38	5	89	-	238
Income tax expense (recovery)	25	1	16	-	(21)	-	21
Preferred stock dividends	-	-	-	-	18	-	18
Net income (loss) attributable to common shareholders	$ 187	$ 42	$ 44	$ 8	$ (152)	$ -	$ 129
For the six months ended June 30, 2024							
Operating revenues from external customers (1)	$ 1,654	$ 977	$ 853	$ 266	$ (115)	$ -	$ 3,635
Inter-segment revenues (1)	4	-	7	-	18	(29)	-
Total operating revenues	1,658	977	860	266	(97)	(29)	3,635
Regulated fuel for generation and purchased power	417	454	-	139	-	(7)	1,003
Regulated cost of natural gas	-	-	236	-	-	-	236
OM&G	391	212	230	67	93	(10)	983
Provincial, state and municipal taxes	134	24	54	2	1	-	215
Depreciation and amortization	306	138	89	36	4	-	573
Income (loss) from equity investments	-	55	10	2	(5)	-	62
Other income, net	29	14	7	5	151	12	218
Interest expense, net (2)	131	85	77	11	180	-	484
Income tax expense (recovery)	36	4	49	-	(40)	-	49
Preferred stock dividends	-	-	-	-	36	-	36
Net income (loss) attributable to common shareholders	$ 272	$ 129	$ 142	$ 18	$ (225)	$ -	$ 336
As at June 30, 2024							
Total assets	$ 22,446	$ 7,646	$ 8,144	$ 1,361	$ 1,568	$ (1,381)	$ 39,784

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established 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 of $7 million for the three months ended June 30, 2024, and $14 million for the six months ended June 30, 2024 between the Gas Utilities and Infrastructure and Other segments.

millions of dollars	Florida Electric Utility	Canadian Electric Utilities	Gas Utilities and Infrastructure	Other Electric Utilities	Other	Inter-Segment Eliminations	Total
For the three months ended June 30, 2023							
Operating revenues from external customers (1)	$ 907	$ 340	$ 282	$ 126	$ (237)	$ -	$ 1,418
Inter-segment revenues (1)	2	-	4	-	(37)	31	-
Total operating revenues	909	340	286	126	(274)	31	1,418
Regulated fuel for generation and purchased power	220	115	-	64	-	(3)	396
Regulated cost of natural gas	-	-	58	-	-	-	58
OM&G	217	90	99	32	43	(10)	471
Provincial, state and municipal taxes	72	11	22	1	1	-	107
Depreciation and amortization	141	71	32	17	2	-	263
Income from equity investments	-	28	6	-	2	-	36
Other income, net	19	7	3	3	69	(44)	57
Interest expense, net (2)	70	41	32	6	74	-	223
Income tax expense (recovery)	31	(2)	14	-	(94)	-	(51)
Preferred stock dividends	-	-	-	-	16	-	16
Net income (loss) attributable to common shareholders	$ 177	$ 49	$ 38	$ 9	$ (245)	$ -	$ 28
For the six months ended June 30, 2023							
Operating revenues from external customers (1)	$ 1,651	$ 844	$ 854	$ 240	$ 262	$ -	$ 3,851
Inter-segment revenues (1)	4	-	7	-	-	(11)	-
Total operating revenues	1,655	844	861	240	262	(11)	3,851
Regulated fuel for generation and purchased power	417	339	-	121	-	(6)	871
Regulated cost of natural gas	-	-	334	-	-	-	334
OM&G	384	191	201	62	77	(14)	901
Provincial, state and municipal taxes	135	22	48	2	2	-	209
Depreciation and amortization	282	138	62	33	4	-	519
Income from equity investments	-	52	11	1	7	-	71
Other income, net	36	14	6	4	41	(9)	92
Interest expense, net (2)	137	85	57	12	158	-	449
Income tax expense (recovery)	52	(6)	44	-	21	-	111
Preferred stock dividends	-	-	-	-	32	-	32
Net income attributable to common shareholders	$ 284	$ 141	$ 132	$ 15	$ 16	$ -	$ 588
As at December 31, 2023							
Total assets	$ 21,119	$ 8,634	$ 7,735	$ 1,311	$ 1,938	$ (1,257)	$ 39,480

(1) All significant inter-company balances and transactions have been eliminated on consolidation except for certain transactions between non-regulated and regulated entities. Management believes elimination of these transactions would understate PP&E, OM&G, or regulated fuel for generation and purchased power. Inter-company transactions that have not been eliminated are measured at the amount of consideration established 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 of $26 million for the three months ended June 30, 2023, and $43 million for the six months ended June 30, 2023 between the Florida Electric Utility, Gas Utilities and Infrastructure and Other segments.

5. REVENUE

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

	Electric			Gas	Other		
millions of 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, 2024							
Regulated Revenue							
Residential	$ 528	$ 217	$ 49	$ 124	$ -	$ -	$ 918
Commercial	243	115	78	104	-	-	540
Industrial	58	70	6	23	-	(4)	153
Other electric	125	9	2	-	-	-	136
Regulatory deferrals	(38)	-	5	-	-	-	(33)
Other (1)	4	12	2	56	-	(2)	72
Finance income (2)(3)	-	-	-	16	-	-	16
Regulated revenue	920	423	142	323	-	(6)	1,802
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	(31)	-	(31)
Other non-regulated operating revenue	-	-	-	5	6	(5)	6
Mark-to-market (3)	-	-	-	-	(162)	2	(160)
Non-regulated revenue	-	-	-	5	(187)	(3)	(185)
Total operating revenues	**$ 920**	**$ 423**	**$ 142**	**$ 328**	**$ (187)**	**$ (9)**	**$ 1,617**
For the six months ended June 30, 2024							
Regulated Revenue							
Residential	$ 937	$ 546	$ 93	$ 392	$ -	$ -	$ 1,968
Commercial	452	253	146	264	-	-	1,115
Industrial	112	137	13	47	-	(7)	302
Other electric	217	21	3	-	-	-	241
Regulatory deferrals	(69)	-	8	-	-	-	(61)
Other (1)	9	20	3	116	-	(4)	144
Finance income (2)(3)	-	-	-	31	-	-	31
Regulated revenue	1,658	977	266	850	-	(11)	3,740
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	49	-	49
Other non-regulated operating revenue	-	-	-	10	15	(11)	14
Mark-to-market (3)	-	-	-	-	(161)	(7)	(168)
Non-regulated revenue	-	-	-	10	(97)	(18)	(105)
Total operating revenues	**$ 1,658**	**$ 977**	**$ 266**	**$ 860**	**$ (97)**	**$ (29)**	**$ 3,635**

(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 dollars	Electric: Florida Electric Utility	Electric: Canadian Electric Utilities	Electric: Other Electric Utilities	Gas: Gas Utilities and Infrastructure	Other: Other	Other: Inter-Segment Eliminations	Total
For the three months ended June 30, 2023							
Regulated Revenue							
Residential	$ 577	$ 199	$ 42	$ 115	$ -	$ -	$ 933
Commercial	270	107	68	80	-	-	525
Industrial	66	14	8	20	-	(3)	105
Other electric	121	10	2	-	-	-	133
Regulatory deferrals	(130)	-	4	-	-	-	(126)
Other (1)	5	10	2	50	-	(2)	65
Finance income (2)(3)	-	-	-	15	-	-	15
Regulated revenue	909	340	126	280	-	(5)	1,650
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	(34)	-	(34)
Other non-regulated operating revenue	-	-	-	6	9	(9)	6
Mark-to-market (3)	-	-	-	-	(249)	45	(204)
Non-regulated revenue	-	-	-	6	(274)	36	(232)
Total operating revenues	$ 909	$ 340	$ 126	$ 286	$ (274)	$ 31	$ 1,418
For the six months ended June 30, 2023							
Regulated Revenue							
Residential	$ 1,016	$ 492	$ 82	$ 429	$ -	$ -	$ 2,019
Commercial	500	234	130	235	-	-	1,099
Industrial	129	78	16	45	-	(7)	261
Other electric	215	21	3	-	-	-	239
Regulatory deferrals	(215)	-	6	-	-	-	(209)
Other (1)	10	19	3	110	-	(4)	138
Finance income (2)(3)	-	-	-	31	-	-	31
Regulated revenue	1,655	844	240	850	-	(11)	3,578
Non-Regulated Revenue							
Marketing and trading margin (4)	-	-	-	-	61	-	61
Other non-regulated operating revenue	-	-	-	11	15	(12)	14
Mark-to-market (3)	-	-	-	-	186	12	198
Non-regulated revenue	-	-	-	11	262	-	273
Total operating revenues	$ 1,655	$ 844	$ 240	$ 861	$ 262	$ (11)	$ 3,851

(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, 2024, the aggregate amount of the transaction price allocated to remaining performance obligations was $474 million (2023 – $466 million). This amount includes $133 million of future performance obligations related to a gas transportation contract between SeaCoast and PGS through 2040. 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 2044.

6. REGULATORY ASSETS AND LIABILITIES

A summary of 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 6 in Emera’s 2023 annual audited consolidated financial statements. Updates to regulatory environments are included below.

As at millions of dollars		**June 30 2024**		December 31 2023
Regulatory assets				
Deferred income tax regulatory assets	**$**	**1,107**	$	1,233
TEC capital cost recovery for early retired assets		**704**		671
Pension and post-retirement medical plan		**374**		364
NSPI FAM		**314**		395
Storm cost recovery clauses		**73**		52
Deferrals related to derivative instruments		**52**		88
Cost recovery clauses		**29**		151
Environmental remediations		**27**		26
Stranded cost recovery		**26**		25
Other (1)		**100**		100
	$	**2,806**	$	3,105
Current	**$**	**187**	$	339
Long-term		**2,619**		2,766
Total regulatory assets	**$**	**2,806**	$	3,105
Regulatory liabilities				
Accumulated reserve − cost of removal	**$**	**916**	$	849
Deferred income tax regulatory liabilities		**863**		830
Cost recovery clauses		**52**		32
Deferrals related to derivative instruments		**35**		17
BLPC Self-insurance fund ("SIF") (note 23)		**30**		29
Storm reserve		**7**		-
Other (1)		**20**		15
	$	**1,923**	$	1,772
Current	**$**	**210**	$	168
Long-term		**1,713**		1,604
Total regulatory liabilities	**$**	**1,923**	$	1,772

(1) Comprised of regulatory assets and liabilities that are not individually significant.

Florida Electric Utility

Base Rates:
On April 2, 2024, TEC requested a base rate increase, reflecting an increased revenue requirement of $297 million USD, effective January 1, 2025, and additional adjustments of $100 million USD and $72 million USD for 2026 and 2027, respectively. TEC’s proposed rates include recovery of solar generation projects, energy storage capacity, a more resilient and modernized energy control center, and other resiliency and reliability projects.

Fuel Recovery:
On April 2, 2024, TEC requested a mid-course adjustment to its fuel and capacity charges, reflecting a $138 million USD reduction over 12 months, from June 2024 through May 2025. The requested reduction is due to a decrease in actual and projected 2024 natural gas prices since TEC submitted its projected 2024 costs in the fall of 2023. On May 7, 2024, the Florida Public Service Commission voted to approve the mid-course adjustment.

Canadian Electric Utilities

NSPI

Hurricane Fiona:
On June 27, 2024, the Nova Scotia Utility and Review Board ("UARB") approved the deferred recognition of $25 million in incremental operating costs incurred during Hurricane Fiona storm restoration efforts in September 2022. Following UARB approval, the $25 million was reclassified to "Regulatory assets" from "Other long-term assets". The UARB also directed NSPI to reclassify $10 million of undepreciated costs related to assets retired because of Hurricane Fiona to "Regulatory assets" from "PP&E" on the Condensed Consolidated Balance Sheets. NSPI will begin amortizing both regulatory assets over a 10-year period beginning July 1, 2024.

Storm Rider:
On April 30, 2024, NSPI applied to the UARB for recovery of $22 million of major storm restoration costs deferred to NSPI's UARB approved storm rider in 2023. If approved, the 2023 costs deferred to the storm rider would be recovered over a 12-month period beginning January 1, 2025

Fuel Recovery:
On April 17, 2024, the UARB approved the sale of $117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation. On April 30, 2024, the transaction closed and the $117 million was remitted to NSPI, which resulted in a corresponding decrease of the FAM regulatory asset. NSPI is collecting the amortization and financing costs related to the $117 million from customers on behalf of Invest Nova Scotia over a 10-year period which began in Q2 2024 and is remitting those amounts to Invest Nova Scotia quarterly.

NSPML

On July 4, 2024, NSPML submitted an application to the UARB requesting recovery of approximately $158 million in Maritime Link costs for 2025.

On December 21, 2023, NSPML received approval from the UARB to collect up to $164 million in 2024 from NSPI for the recovery of costs associated with the Maritime Link subject to a holdback of $4 million per month. There was no holdback recorded year-to-date in 2024.

Gas Utilities and Infrastructure

NMGC

Base Rates:
On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates to become effective in October 2024. On March 1, 2024, NMGC filed with the NMPRC a settlement with the support of all parties in the case for an increase of $30 million USD in annual base revenues and maintaining NMGC's return on equity ("ROE") at 9.375 per cent. The rates reflect the recovery of increased operating costs and capital investments in pipeline projects and related infrastructure, as well as a new customer information and billing system. NMGC also agreed to withdraw, and to not reassert in a future rate case application, its request for a regulatory asset for costs associated with its 2022 application for a certificate of public convenience and necessity for a liquefied natural gas storage facility in New Mexico. The NMPRC approved the rate case settlement on July 25, 2024.

Other Electric Utilities

BLPC

Barbados Domestic Tax Rate Change:
On May 24, 2024, the Government of Barbados signed the Income Tax (Amendment and Validation) Act into law. The legislation, effective January 1, 2024, implemented a corporate income tax rate of 9 per cent, requiring BLPC to remeasure its deferred income tax liabilities. On July 18, 2024, BLPC requested the deferred recovery of the $5 million USD remeasurement. BLPC is seeking amortization of the costs over a period to be approved by the Fair Trading Commission, Barbados ("FTC") during a future rate setting process.

Clean Energy Transition Rider ("CETR"):
On May 31, 2023, the FTC approved BLPC's application to establish a CETR to recover prudently incurred costs associated with its clean energy transition project. The mechanism is intended to facilitate the timely recovery between rate cases of costs associated with approved renewable energy assets. On October 5, 2023, BLPC applied to the FTC to recover the costs of a battery storage system through the mechanism. On May 6, 2024, the FTC approved certain aspects of BLPC's application, including the recovery for capital investment in a 15 MW battery storage system. BLPC is currently evaluating the impact of operationalizing the decision.

Base Rates:
In 2021, BLPC submitted a general rate review application to the FTC. In September 2022, the FTC granted BLPC interim rate relief, allowing an increase in base rates of approximately $1 million USD per month. On February 15, 2023, the FTC issued a decision on the application which included the following significant items: an allowed regulatory ROE of 11.75 per cent, an equity capital structure of 55 per cent, a directive to update the major components of rate base to September 16, 2022, and a directive to establish regulatory liabilities totalling approximately $71 million USD. On March 7, 2023, BLPC filed a Motion for Review and Variation (the "Motion") and applied for a stay of the FTC's decision, which was subsequently granted. On November 20, 2023, the FTC issued their decision dismissing the Motion. Interim rates continue to be in effect through to a date to be determined in a final decision and order.

On December 1, 2023, BLPC appealed certain aspects of the FTC's February 15 and November 20, 2023 decisions to the Supreme Court of Barbados in the High Court of Justice (the "Court") and requested that they be stayed. On December 11, 2023, the Court granted the stay. BLPC's position is that the FTC made errors of law and jurisdiction in their decisions and believes the success of the appeal is probable, and as a result, the adjustments to BLPC's final rates and rate base, including any adjustments to regulatory assets and liabilities, have not been recorded at this time. The appeal is currently scheduled to be heard in December 2024.

GBPC

Base Rates:
On August 1, 2024, as required by the Grand Bahamas Port Authority ("GBPA") Operating Protocol and Regulatory Framework Agreement, GBPC filed a rate plan proposal. The proposal seeks a revision in base rates, charges and tariff classifications effective January 1, 2025 for a three-year period ending December 31, 2027. The proposed rates are based on an 8.5 per cent to 8.7 per cent allowable regulated return on rate base and a target regulatory ROE of 12.87 per cent.

Electricity Act, 2024:
On June 1, 2024, the Electricity Act, 2024 took effect. The legislation purports to remove the jurisdiction of the GBPA over GBPC and to have the Utilities Regulation and Competition Authority, another Bahamian regulator, regulate GBPC.

7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY INCOME

millions of dollars	June 30 2024	Carrying Value as at December 31 2023	2024	Equity Income (loss) for three months ended June 30 2023	2024	Equity Income for the six months ended June 30 2023	Percentage of Ownership 2024
NSPML	**$ 477**	$ 489	**$ 13**	$ 13	**$ 26**	$ 21	100.0
M&NP (1)	**119**	118	**5**	6	**10**	11	12.9
Lucelec (1)	**51**	48	**1**	-	**2**	1	19.5
LIL (2)	**-**	747	**12**	15	**29**	31	-
Bear Swamp (3)	**-**	-	**(3)**	2	**(5)**	7	50.0
	$ 647	$ 1,402	**$ 28**	$ 36	**$ 62**	$ 71	

(1) Emera has significant influence over the operating and financial decisions of these companies through Board representation and therefore, records its investment in these entities using the equity method.
(2) On June 4, 2024, Emera completed the sale of its 31.1 per cent indirect equity interest in the LIL. For further details, refer to note 3.
(3) The investment balance in Bear Swamp is in a credit position primarily as a result of a $179 million distribution received in 2015. Bear Swamp's credit investment balance of $93 million (2023 – $81 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 as follows:

As at millions of dollars	June 30 2024	December 31 2023
Current assets	**$ 21**	$ 21
PP&E	**1,448**	1,473
Regulatory assets	**281**	272
Non-current assets	**27**	29
Total assets	**$ 1,777**	$ 1,795
Current liabilities	**$ 51**	$ 48
Long-term debt (1)	**1,090**	1,109
Non-current liabilities	**159**	149
Equity	**477**	489
Total liabilities and equity	**$ 1,777**	$ 1,795

(1) The project debt has been guaranteed by the Government of Canada.

8. OTHER INCOME, NET

For the millions of dollars	2024	Three months ended June 30 2023	2024	Six months ended June 30 2023
Gain on sale, net of transaction costs (1)	**$ 182**	$ -	**$ 182**	$ -
Interest income	**4**	12	**9**	25
AFUDC - equity	**12**	9	**21**	17
Pension non-service cost recovery	**9**	7	**18**	16
FX (losses) gains	**(19)**	18	**(22)**	21
Other	**2**	11	**10**	13
	$ 190	$ 57	**$ 218**	$ 92

(1) For more information related to the gain on sale, after transaction costs, of Emera's indirect minority equity interest in the LIL, refer to note 3.

9. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of dollars	Three months ended June 30 **2024**	2023	Six months ended June 30 **2024**	2023
Interest on debt	**$ 248**	$ 232	**$ 501**	$ 462
Allowance for borrowed funds used during construction	**(5)**	(4)	**(9)**	(7)
Other	**(5)**	(5)	**(8)**	(6)
	$ 238	$ 223	**$ 484**	$ 449

10. 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 dollars	Three months ended June 30 **2024**	2023	Six months ended June 30 **2024**	2023
Income (loss) before provision for income taxes	**$ 168**	$ (7)	**$ 421**	$ 731
Statutory income tax rate	**29%**	29%	**29%**	29%
Income taxes, at statutory income tax rate	**49**	(2)	**122**	212
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(9)**	(13)	**(30)**	(45)
Tax credits	**(17)**	(10)	**(25)**	(17)
Additional impact from the sale of LIL equity interest	**22**	-	**22**	-
Amortization of deferred income tax regulatory liabilities	**(10)**	(11)	**(16)**	(16)
Foreign tax rate variance	**(8)**	(11)	**(15)**	(19)
Tax effect of equity earnings	**(4)**	(4)	**(8)**	(7)
Other	**(2)**	-	**(1)**	3
Income tax expense (recovery)	**$ 21**	$ (51)	**$ 49**	$ 111
Effective income tax rate	**13%**	729%	**12%**	15%

Excessive Interest and Financing Expenses Limitation (“EIFEL”) Regime:
On June 20, 2024, Bill C-59, an Act to implement certain provisions of the fall economic statement tabled in Parliament on November 21, 2023, and certain provisions of the budget tabled in Parliament on March 28, 2023, was enacted. Bill C-59 includes the EIFEL regime, which is effective January 1, 2024. EIFEL applies to limit a company’s net interest and financing expense deduction to no more than 30 per cent of earnings before interest, income taxes, depreciation, and amortization for tax purposes. Any denied interest and financing expenses under the EIFEL regime can be carried forward indefinitely. The EIFEL regime did not have a material impact on the Company in Q2 2024.

Canadian Global Minimum Tax Act (“GMTA”):
On June 20, 2024, Bill C-69, an Act to implement certain provisions of the budget tabled in Parliament on April 16, 2024, was enacted. Bill C-69 includes the GMTA, a regime based on the rules of the Organisation for Economic Co-operation and Development (“OECD”). The GMTA ensures that large multinational corporations are subject to a minimum effective tax rate of 15 per cent on their profits wherever they do business. The GMTA did not have a material impact on the Company in Q2 2024.

Barbados Domestic Tax Rate Change:
On May 24, 2024, the Government of Barbados signed the Income Tax (Amendment and Validation) Act into law. The legislation, effective January 1, 2024, implemented a corporate income tax rate of 9 per cent, requiring BLPC to remeasure its deferred income tax liabilities. On July 18, 2024, BLPC requested the deferred recovery of the $5 million USD remeasurement. BLPC is seeking amortization of the costs over a period to be approved by the FTC during a future rate setting process.

United States Inflation Reduction Act ("IRA"):
On August 16, 2022, the IRA was signed into legislation. The IRA includes numerous tax incentives for clean energy, such as the extension and modification of existing investment and production tax credits for projects placed in service through 2024, and introduces new technology-neutral clean energy related tax credits beginning in 2025. As of June 30, 2024, the Company has recorded a $55 million (December 31, 2023 – $30 million) regulatory liability on the Consolidated Balance Sheets in recognition of its obligation to pass the incremental tax benefits realized to customers.

11. COMMON STOCK

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

Issued and outstanding:	millions of shares	millions of dollars	
Balance, December 31, 2023	284.12	$	8,462
Issuance of common stock under ATM program (1)	0.72		35
Issued under the DRIP, net of discounts	3.06		142
Senior management stock options exercised and ECSPP	0.40		18
Balance, June 30, 2024	**288.30**	**$**	**8,657**

(1) For the three months ended June 30, 2024, 226,443 common shares were issued under Emera's ATM program at an average price of $47.72 per share for gross proceeds of $11 million ($11 million, net of after-tax issuance costs). For the six months ended June 30, 2024, 724,996 common shares were issued under Emera's ATM program at an average price of $48.21 per share for gross proceeds of $35 million ($35 million net of after-tax issuance costs). As at June 30, 2024, an aggregate gross sales limit of $165 million remained available for issuance under the ATM program.

12. EARNINGS PER SHARE

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

For the millions of dollars (except per share amounts)	Three months ended June 30 **2024**	2023	Six months ended June 30 **2024**	2023
Numerator				
Net income attributable to common shareholders	**$ 129.0**	$ 27.5	**$ 336.2**	$ 587.9
Diluted numerator	**129.0**	27.5	**336.2**	587.9
Denominator				
Weighted average shares of common stock outstanding – basic	**287.3**	272.3	**286.2**	271.5
Stock-based compensation	**0.1**	0.3	**0.1**	0.3
Weighted average shares of common stock outstanding – diluted	**287.4**	272.6	**286.3**	271.8
Earnings per common share				
Basic	**$ 0.45**	$ 0.10	**$ 1.17**	$ 2.17
Diluted	**$ 0.45**	$ 0.10	**$ 1.17**	$ 2.16

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of AOCI, net of tax, are as follows:

millions of dollars		Unrealized gain on translation of self-sustaining foreign operations		Net change in net investment hedges		Gains (losses) 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, 2024												
Balance, January 1, 2024	**$**	**369**	**$**	**(24)**	**$**	**14**	**$**	**(2)**	**$**	**(52)**	**$**	**305**
OCI before reclassifications		**405**		**(55)**				**1**				**351**
Amounts reclassified from AOCI						**(1)**				**1**		**-**
Net current period OCI		**405**		**(55)**		**(1)**		**1**		**1**		**351**
Balance, June 30, 2024	**$**	**774**	**$**	**(79)**	**$**	**13**	**$**	**(1)**	**$**	**(51)**	**$**	**656**
For the six months ended June 30, 2023												
Balance, January 1, 2023	$	639	$	(62)	$	16	$	(2)	$	(13)	$	578
OCI before reclassifications		(247)		36		1		-		-		(210)
Amounts reclassified from AOCI		-		-		(1)		-		(5)		(6)
Net current period OCI		(247)		36		-		-		(5)		(216)
Balance, June 30, 2023	$	392	$	(26)	$	16	$	(2)	$	(18)	$	362

The reclassifications out of AOCI are as follows:

For the millions of dollars		Three months ended June 30				Six months ended June 30			
			2024		2023		**2024**		2023
	Affected line item in the Condensed Consolidated Interim Financial Statements	Amounts reclassified from AOCI							
Gain on derivatives recognized as cash flow hedges									
Interest rate hedge	Interest expense, net	**$**	**-**	$	-	**$**	**(1)**	$	(1)
Net change in unrecognized pension and post-retirement benefit costs									
Amounts reclassified into obligations	Pension and post-retirement benefits		**-**		(1)		**1**		(5)
Total reclassifications out of AOCI, for the period		**$**	**-**	$	(1)	**$**	**-**	$	(6)

14. 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 ("FX") 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 treatment of these contracts under this exception if the criteria are no longer met.

2. Derivatives that qualify for hedge accounting are recorded at FV 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 FV of derivatives is deferred to AOCI and recognized in income in the same period the related hedged item is realized.

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

3. Derivatives entered into by NSPI, 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 FV on the balance sheet as derivative assets or liabilities. The change in FV 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. Based on current direction from the FPSC, TEC and PGS have no derivatives related to hedging.

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 FV, 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 dollars	**June 30 2024**	December 31 2023	**June 30 2024**	December 31 2023
Regulatory deferral:				
Commodity swaps and forwards	**$ 45**	$ 16	**$ 52**	$ 76
FX forwards	**10**	3	**3**	3
	55	19	**55**	79
HFT derivatives:				
Power swaps and physical contracts	**11**	29	**10**	36
Natural gas swaps, futures, forwards, physical contracts	**191**	319	**496**	531
	202	348	**506**	567
Other derivatives:				
Equity derivatives	**-**	4	**9**	-
FX forwards	**1**	18	**7**	7
	1	22	**16**	7
Total gross derivatives	**258**	389	**577**	653
Impact of master netting agreements:				
Regulatory deferral	**(6)**	(3)	**(6)**	(3)
HFT derivatives	**(90)**	(146)	**(90)**	(146)
Total impact of master netting agreements	**(96)**	(149)	**(96)**	(149)
Total derivatives	**$ 162**	$ 240	**$ 481**	$ 504
Current (1)	**119**	174	**397**	386
Long-term (1)	**43**	66	**84**	118
Total derivatives	**$ 162**	$ 240	**$ 481**	$ 504

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

Cash Flow Hedges

On May 26, 2021, a treasury lock was settled for a gain of $19 million that is being amortized through interest expense over 10 years as the underlying hedged item settles. As of June 30, 2024, the unrealized gain in AOCI was $13 million, net of tax (December 31, 2023 – $14 million, net of tax). For the three and six months ended June 30, 2024, unrealized gains of nil (2023 – nil) and $1 million (2023 - $1 million) respectively have been reclassified from AOCI into interest expense, net. The Company expects $2 million of unrealized gains currently in AOCI to be reclassified into net income within the next twelve months.

Regulatory Deferral

The Company has recorded the following changes with respect to derivatives receiving regulatory deferral:

millions of dollars	**Commodity swaps and forwards**	**FX forwards**	Physical natural gas purchases	Commodity swaps and forwards	FX forwards
For the three months ended June 30		**2024**			2023
Unrealized gain (loss) in regulatory assets	**$ 5**	**$ 1**	$ -	$ (9)	$ (3)
Unrealized gain (loss) in regulatory liabilities	**(3)**	**3**	1	8	(4)
Realized gain in regulatory assets	**(3)**	**-**	-	(4)	-
Realized loss in regulatory liabilities	**1**	**-**	-	3	-
Realized (gain) loss in inventory (1)	**3**	**(2)**	-	4	(4)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**18**	**(2)**	(3)	7	(2)
Total change in derivative instruments	**$ 21**	**$ -**	$ (2)	$ 9	$ (13)
For the six months ended June 30		**2024**			2023
Unrealized gain (loss) in regulatory assets	**$ 13**	**$ 1**	$ -	$ (29)	$ (3)
Unrealized gain (loss) in regulatory liabilities	**12**	**14**	(3)	(59)	(2)
Realized gain in regulatory assets	**(4)**	**-**	-	-	-
Realized loss in regulatory liabilities	**-**	**-**	-	4	-
Realized (gain) loss in inventory (1)	**7**	**(4)**	-	5	(9)
Realized (gain) loss in regulated fuel for generation and purchased power (2)	**25**	**(4)**	(42)	(20)	(2)
Other	**-**	**-**	-	(15)	-
Total change in derivative instruments	**$ 53**	**$ 7**	$ (45)	$ (114)	$ (16)

(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 and hedging relationships that have been terminated or the hedged transaction is no longer probable.

As at June 30, 2024, the Company had the following notional volumes designated for regulatory deferral that are expected to settle as outlined below:

millions	2024	2025-2026
Physical natural gas purchases:		
Natural gas (MMBtu)	4	6
Commodity swaps and forwards purchases:		
Natural gas (MMBtu)	11	22
Power (MWh)	1	2
Coal (metric tonnes)	-	1
FX swaps and forwards:		
FX contracts (millions of USD)	$ 147	$ 138
Weighted average rate	1.3447	1.3327
% of USD requirements	62%	18%

HFT Derivatives

The Company has recognized the following realized and unrealized gains (losses) with respect to HFT derivatives:

For the millions of dollars	Three months ended June 30 **2024**	2023	Six months ended June 30 **2024**	2023
Power swaps and physical contracts in non-regulated operating revenues	**$ 1**	$ -	**$ 11**	$ -
Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues	**(11)**	(22)	**139**	817
Total gains (losses) in net income	**$ (10)**	$ (22)	**$ 150**	$ 817

As at June 30, 2024, the Company had the following notional volumes of outstanding HFT derivatives that are expected to settle as outlined below:

millions	2024	2025	2026	2027	2028 and thereafter
Natural gas purchases (MMBtu)	202	152	84	41	103
Natural gas sales (MMBtu)	238	160	42	12	10
Power purchases (MWh)	1	-	-	-	-
Power sales (MWh)	1	-	-	-	-

Other Derivatives

As at June 30, 2024, the Company had equity derivatives in place to manage cash flow risk associated with forecasted future cash settlements of deferred compensation obligations and FX forwards in place to manage cash flow risk associated with forecasted USD cash inflows. The equity derivatives hedge the return on 2.9 million shares and extends until December 2024. The FX forwards have a combined notional amount of $557 million USD and expire in 2024 through 2026.

The Company has recognized the following realized and unrealized gains (losses) with respect to other derivatives:

millions of dollars	**FX forwards**	**Equity derivatives**	FX forwards	Equity derivatives
For the three months ended June 30		**2024**		2023
Unrealized loss in OM&G	**$ -**	**$ (6)**	$ -	$ (3)
Unrealized gain (loss) in other income, net	**(14)**	**-**	17	-
Realized loss in other income, net	**(3)**	**-**	(2)	-
Total gains (losses) in net income	**$ (17)**	**$ (6)**	$ 15	$ (3)
For the six months ended June 30		**2024**		2023
Unrealized gain (loss) in OM&G	**$ -**	**$ (14)**	$ -	$ 8
Unrealized gain (loss) in other income, net	**(16)**	**-**	23	-
Realized loss in other income, net	**(4)**	**-**	(5)	-
Total gains (losses) in net income	**$ (20)**	**$ (14)**	$ 18	$ 8

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 internally assesses credit risk 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, FX 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, North American Energy Standards Board agreements and/or Edison Electric Institute agreements. The Company believes entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at June 30, 2024, the Company had $162 million (December 31, 2023 – $142 million) in financial assets considered to be past due, which had been outstanding for an average 59 days. The FV of these financial assets was $147 million (December 31, 2023 – $127 million), the difference of which is included in the allowance for credit losses. These assets primarily relate to accounts receivable from electric and gas revenue.

As at millions of dollars	**June 30 2024**	December 31 2023
Cash collateral provided to others	**$ 89**	$ 101
Cash collateral received from others	**$ 6**	$ 22

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, 2024, the total FV of derivatives in a liability position was $481 million (December 31, 2023 – $504 million). If the credit ratings of the Company were reduced below investment grade, the full value of the net liability position could be required to be posted as collateral for these derivatives.

15. FV MEASUREMENTS

The Company is required to determine the FV of all derivatives except those which qualify for the NPNS exemption (see note 14), and uses a market approach to do so. The three levels of the FV 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 FV measurement.

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

As at millions of dollars	Level 1	Level 2	Level 3	June 30, 2024 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 15	$ 24	$ -	$ 39
FX forwards	-	10	-	10
	15	34	-	49
HFT derivatives:				
Power swaps and physical contracts	-	6	3	9
Natural gas swaps, futures, forwards, physical contracts and related transportation	16	74	13	103
	16	80	16	112
Other derivatives:				
FX forwards	-	1	-	1
Total assets	31	115	16	162
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	29	17	-	46
FX forwards	-	3	-	3
	29	20	-	49
HFT derivatives:				
Power swaps and physical contracts	1	4	2	7
Natural gas swaps, futures, forwards and physical contracts	(2)	37	374	409
	(1)	41	376	416
Other derivatives:				
FX forwards	-	7	-	7
Equity derivatives	9	-	-	9
	9	7	-	16
Total liabilities	37	68	376	481
Net assets (liabilities)	$ (6)	$ 47	$ (360)	$ (319)

As at millions of dollars	Level 1	Level 2	Level 3	December 31, 2023 Total
Assets				
Regulatory deferral:				
Commodity swaps and forwards	$ 7	$ 6	$ -	$ 13
FX forwards	-	3	-	3
	7	9	-	16
HFT derivatives:				
Power swaps and physical contracts	(5)	23	-	18
Natural gas swaps, futures, forwards, physical contracts and related transportation	42	108	34	184
	37	131	34	202
Other derivatives:				
Equity derivatives	4	-	-	4
FX forwards	-	18	-	18
	4	18	-	22
Total assets	48	158	34	240
Liabilities				
Regulatory deferral:				
Commodity swaps and forwards	43	30	-	73
FX forwards	-	3	-	3
	43	33	-	76
HFT derivatives:				
Power swaps and physical contracts	-	24	-	24
Natural gas swaps, futures, forwards and physical contracts	13	19	365	397
	13	43	365	421
Other derivatives:				
FX forwards	-	7	-	7
Total liabilities	56	83	365	504
Net assets (liabilities)	$ (8)	$ 75	$ (331)	$ (264)

The change in the FV of the Level 3 financial assets and liabilities was as follows:

	Three months ended June 30, 2024			Six months ended June 30, 2024		
	HFT Derivatives			*HFT Derivatives*		
millions of dollars	Power	Natural gas	**Total**	Power	Natural gas	**Total**
Assets						
Balance, beginning of period	$ 1	$ 13	**$ 14**	$ -	$ 34	**$ 34**
Total realized and unrealized gains (losses) included in non-regulated operating revenues	2	-	**2**	3	(21)	**(18)**
Balance, June 30, 2024	**$ 3**	**$ 13**	**$ 16**	**$ 3**	**$ 13**	**$ 16**
Liabilities						
Balance, beginning of period	$ 1	$ 351	**$ 352**	$ -	$ 365	**$ 365**
Total realized and unrealized losses included in non-regulated operating revenues	1	23	**24**	2	9	**11**
Balance, June 30, 2024	**$ 2**	**$ 374**	**$ 376**	**$ 2**	**$ 374**	**$ 376**

Significant unobservable inputs used in the FV measurement of Emera's natural gas and power derivatives include third-party sourced pricing for instruments based on illiquid markets. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) FV measurement. Other unobservable inputs used include 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. 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.

The Company uses a modelled pricing valuation technique for determining the FV of Level 3 derivative instruments. The following table outlines quantitative information about the significant unobservable inputs used in the FV measurements categorized within Level 3 of the FV hierarchy:

As at millions of dollars	FV Assets	 Liabilities	Significant Unobservable Input	Low	High	June 30, 2024 Weighted Average (1)
HFT derivatives – Power swaps and physical contracts	3	2	Third-party pricing	$20.80	$141.80	$86.11
HFT derivatives – Natural gas swaps, futures, forwards and physical contracts	13	374	Third-party pricing	$1.31	$15.99	$7.33
Total	**$ 16**	**$ 376**				
Net liability		**$ 360**				

(1) Unobservable inputs were weighted by the relative FV of the instruments.

Long-term debt is a financial liability not measured at FV on the Condensed Consolidated Balance Sheets. The balance consisted of the following:

As at millions of dollars	Carrying Amount	FV	Level 1	Level 2	Level 3	Total
June 30, 2024	**$ 18,602**	**$ 17,224**	**$ -**	**$ 16,970**	**$ 254**	**$ 17,224**
December 31, 2023	$ 18,365	$ 16,621	$ -	$ 16,363	$ 258	$ 16,621

The Company has designated $1.2 billion USD denominated Hybrid Notes as a hedge of the foreign currency exposure of its net investment in USD denominated operations. An after-tax foreign currency loss of $16 million was recorded in AOCI for the three months ended June 30, 2024 (2023 – $35 million after-tax gain) and an after-tax foreign currency loss of $55 million was recorded for the six months ended June 30, 2024 (2023 – $36 million after-tax gain).

16. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera provides energy 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 $40 million for the three months ended June 30, 2024 (2023 – $41 million) and $82 million for the six months ended June 30, 2024 (2023 – $78 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 $2 million for the three months ended June 30, 2024 (2023 – $3 million) and $6 million for the six months ended June 30, 2024 (2023 – $8 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, 2024 and at December 31, 2023.

17. RECEIVABLES AND OTHER CURRENT ASSETS

As at millions of dollars		**June 30 2024**		December 31 2023
Customer accounts receivable – billed	**$**	**790**	$	805
Customer accounts receivable – unbilled		**328**		363
Capitalized transportation capacity (1)		**287**		358
Prepaid expenses		**148**		105
Income tax receivable		**11**		10
Allowance for credit losses		**(15)**		(15)
Other		**196**		191
Total receivables and other current assets	**$**	**1,745**	$	1,817

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

18. EMPLOYEE BENEFIT PLANS

Emera maintains a number of contributory defined-benefit ("DB") and defined-contribution ("DC") 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, New Mexico, Barbados, and Grand Bahama Island.

Emera's net periodic benefit cost included the following:

For the millions of dollars	Three months ended June 30 **2024**	 2023	Six months ended June 30 **2024**	 2023
DB pension plans				
Service cost	**$ 9**	$ 7	**$ 17**	$ 15
Non-service cost:				
Interest cost	**28**	28	**55**	56
Expected return on plan assets	**(41)**	(41)	**(80)**	(81)
Current year amortization of:				
Actuarial losses	**1**	-	**1**	-
Regulatory asset	**2**	2	**4**	3
Total non-service costs	**(10)**	(11)	**(20)**	(22)
Total DB pension plans	**(1)**	(4)	**(3)**	(7)
Non-pension benefit plans				
Service cost	**-**	1	**1**	1
Non-service cost:				
Interest cost	**3**	4	**6**	7
Expected return on plan assets	**-**	(1)	**(1)**	(1)
Current year amortization of regulatory asset	**(1)**	(1)	**(2)**	(2)
Total non-service costs	**2**	2	**3**	4
Total non-pension benefit plans	**2**	3	**4**	5
Total DB plans	**$ 1**	$ (1)	**$ 1**	$ (2)

Emera's pension and non-pension contributions related to these DB plans for the three months ended June 30, 2024 were $16 million (2023 – $21 million), and for the six months ended June 30, 2024 were $28 million (2023 – $35 million). Annual employer contributions to the DB pension plans are estimated to be $34 million for 2024. Emera's contributions related to the DC plans for the three months ended June 30, 2024 were $13 million (2023 – $11 million) and $25 million (2023 – $22 million) for the six months ended June 30, 2024.

19. 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 23 in Emera's 2023 annual audited consolidated financial statements, and below for 2024 short-term debt financing activity.

Florida Electric Utilities

On April 1, 2024, TEC amended its $800 million USD unsecured committed revolving credit facility to extend the maturity date from December 17, 2026 to December 1, 2028. There were no other changes in commercial terms from the prior agreement.

Other

On April 1, 2024, TECO Finance amended its $400 million USD unsecured committed revolving credit facility to extend the maturity date from December 17, 2026 to December 1, 2028. There were no other changes in commercial terms from the prior agreement.

On February 16, 2024, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from February 19, 2024 to February 19, 2025. There were no other changes in commercial terms from the prior agreement. On July 19, 2024, Emera reduced the amount of the facility from $400 million to $200 million.

20. LONG-TERM DEBT

For details regarding long-term debt, refer to note 25 in Emera's 2023 annual audited consolidated financial statements, and below for 2024 long-term debt financing activity.

Florida Electric Utilities

On July 12, 2024, TEC repaid a $300 million note upon maturity. This note was repaid with proceeds from commercial paper.

On January 30, 2024, TEC issued $500 million USD of senior unsecured bonds that bear interest at 4.90 per cent with a maturity date of March 1, 2029. Proceeds from the issuance were primarily used for the repayment of short-term borrowings outstanding under the 5-year credit facility.

Canadian Electric Utilities

On June 24, 2024, NSPI amended its unsecured committed revolving credit facility to extend the maturity date from December 16, 2027 to June 24, 2029. There were no other material changes in commercial terms from the prior agreement.

On June 24, 2024, NSPI amended its unsecured non-revolving credit facility to extend the maturity date from July 15, 2024 to June 24, 2025 and reduce the facility from $400 million to $300 million. There were no other material changes in commercial terms from the prior agreement.

On June 13, 2024, NSPI entered a non-revolving credit facility to finance the Battery Energy Storage Project. NSPI can request funds under the facility quarterly for amounts related to incurred project costs up to the total commitment of the lessor of $120 million and 45.06 per cent of the total eligible project costs over the term of the agreement. The facility will be available until 6 months after completion of the project, not to exceed May 21, 2027 and matures 20 years following the end of the period. On July 26, 2024, NSPI drew $16 million from the facility which bears interest at 2.51 per cent.

Gas Utilities and Infrastructure

On July 30, 2024, New Mexico Gas Intermediate, Inc. ("NMGI") repaid its $150 million USD fixed rate notes upon maturity.

Other Electric Utilities

On May 2, 2024, BLPC amended its $92 million Barbadian dollar ($46 million USD) loan facility to extend the maturity date from February 19, 2025 to July 19, 2028. There were no other material changes in commercial terms from the prior agreement.

Other

On June 24, 2024, Emera amended its unsecured committed revolving credit facility increasing the facility from $900 million to $1,300 million. Emera also extended the maturity date from June 24, 2027 to June 24, 2029. There were no other material changes in commercial terms from the prior agreement.

On June 24, 2024, Emera repaid its $400 million unsecured non-revolving credit facility set to mature in August 2024.

On June 15, 2024, Emera Finance repaid its $300 million USD senior notes upon maturity.

On June 18, 2024, EUSHI Finance, Inc., completed an issuance of $500 million USD fixed-to-fixed reset rate junior subordinated notes. The notes initially bear interest at a rate of 7.625 per cent, and will reset on December 15, 2029, and every five years thereafter, to a rate per annum equal to the five-year U.S. treasury rate plus 3.136 per cent. The notes mature on December 15, 2054. EUSHI Finance, Inc., at its option, may redeem the notes, in whole or in part, 90 days prior to the first interest reset date, and any semi-annual interest payment date thereafter, at a redemption price equal to the principal amount.

21. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at June 30, 2024, contractual commitments (excluding pensions and other post-retirement obligations, long-term debt and asset retirement obligations) for each of the next five years and in aggregate thereafter consisted of the following:

millions of dollars	2024	2025	2026	2027	2028	Thereafter	Total
Transportation (1)	$ 406	$ 583	$ 447	$ 417	$ 367	$ 2,752	$ 4,972
Purchased power (2)	158	288	275	324	325	3,564	4,934
Capital projects	798	220	89	8	-	1	1,116
Fuel, gas supply and storage	313	296	71	5	1	-	686
Other	68	155	61	49	36	225	594
	$ 1,743	$ 1,542	$ 943	$ 803	$ 729	$ 6,542	$ 12,302

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $133 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(2) Annual requirement to purchase electricity from Independent Power Producers or other utilities over varying contract lengths.

NSPI has a contractual obligation to pay NSPML for use of the Maritime Link over approximately 38 years from its January 15, 2018 in-service date. In December 2023, the UARB approved the collection of up to $164 million from NSPI for the recovery of Maritime Link costs in 2024. The timing and amounts payable to NSPML for the remainder of the 38-year commitment period are subject to UARB approval.

Emera has committed to obtain certain transmission rights in New Brunswick during summer periods (April through October, inclusive) for Nalcor Energy's use, if requested, effective August 15, 2021 and continuing for 50 years. As transmission rights are contracted, the obligations are included within “Other” in the above table.

B. Legal Proceedings

Superfund and Former Manufactured Gas Plant Sites

Previously, TEC had been a potentially responsible party ("PRP") for certain superfund sites through its Tampa Electric and former PGS divisions, as well as for certain former manufactured gas plant sites through its PGS division. As a result of the separation of the PGS division into a separate legal entity, Peoples Gas System, Inc. is also now a PRP for those sites (in addition to third party PRPs for certain sites). While the aggregate joint and several liability associated with these sites has not changed as a result of the PGS legal separation, the sites continue to present the potential for significant response costs. As at June 30, 2024, the aggregate financial liability of the Florida utilities is estimated to be $16 million ($11 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 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 the Florida utilities. The estimates to perform the work are based on the Florida utilities' 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, the Florida utilities could be liable for more than their 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.

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

For information on principal financial risks which could materially affect the Company in the normal course of business, refer to note 27 in Emera's 2023 annual audited consolidated financial statements. Risks associated with derivative instruments and FV measurements are discussed in note 14 and note 15. There have been no material changes to the principal financial risks as of June 30, 2024.

D. Guarantees and Letters of Credit

Emera's guarantees and letters of credit are consistent with those disclosed in the Company's 2023 audited annual consolidated financial statements, with material updates as noted below:

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 2025. The amount committed as at June 30, 2024 was $58 million (December 31, 2023 – $56 million).

Emera has provided an indemnity to a counterparty in relation to certain future tax amounts that could arise from specific future changes in Canadian federal law, subject to certain conditions and limitations. No such changes in law have been proposed at this time. A reasonable estimate of the potential amount of future payments that could result from future claims under this indemnity cannot be calculated, but the risk of having to make any payments under this indemnity is considered to be remote.

22. SUPPLEMENTARY INFORMATION TO CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the	Six months ended June 30			
millions of dollars		**2024**		2023
Changes in non-cash working capital:				
Inventory	**$**	**13**	$	(67)
Receivables and other current assets (1)		**56**		728
Accounts payable		**(110)**		(678)
Other current liabilities (2)		**(10)**		(195)
Total non-cash working capital	**$**	**(51)**	$	(212)

1) The six months ended June 30, 2023, includes $162 million related to the January 2023 settlement of NMGC gas hedges. Offsetting change in regulatory liabilities is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.
2) The six months ended June 30, 2023, includes $(166) million related to the decreased accrual for the Nova Scotia Cap-and-Trade emissions compliance charges. Offsetting regulatory asset (FAM) balance is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.

For the	Six months ended June 30			
millions of dollars		**2024**		2023
Supplemental disclosure of non-cash activities:				
Common share dividends reinvested	**$**	**142**	$	139
Increase in accrued capital expenditures	**$**	**4**	$	30
Accrued proceeds from disposal of investment subject to significant influence	**$**	**25**	$	-
Supplemental disclosure of operating activities:				
Net change in short-term regulatory assets and liabilities	**$**	**185**	$	(71)

23. VARIABLE INTEREST ENTITIES

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

BLPC established a SIF, primarily for the purpose of building a fund to cover risk against damage and consequential loss to certain generating, transmission, and distribution systems. ECI holds a variable interest in the SIF for which it was determined that ECI was the primary beneficiary and, accordingly, the SIF must be consolidated by ECI. In its determination that ECI controls the SIF, management considered that, in substance, 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 asset", "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, 2024**		December 31, 2023	
millions of dollars	**Total assets**	**Maximum exposure to loss**	Total assets	Maximum exposure to loss
Unconsolidated VIEs in which Emera has variable interests				
NSPML (equity accounted)	**$ 477**	**$ 6**	$ 489	$ 6

24. SUBSEQUENT EVENTS

These unaudited condensed consolidated interim financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through August 9, 2024, the date the unaudited condensed consolidated interim financial statements were issued.