# 2023 Annual Report

Emera

# 2023 Financial Highlights

Data is as of December 31, 2023, unless otherwise indicated.

**10%**

**annualized 10-year total shareholder return**

**$2.96**

**annual adjusted EPS[1]**

**64%**

**of adjusted net income[2], excluding Corporate costs, comes from Florida**

**$2.9B**

**invested in 2023, leading to a 10.2% annual increase in rate base**

**4%**

**dividend increase in 2023**

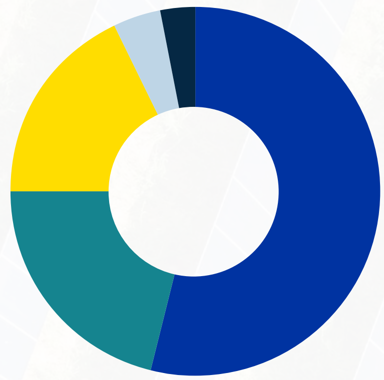
1 Adjusted earnings per share ("EPS") is a non-GAAP ratio, which does not have standardized meaning under USGAAP. For more information, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2023 MD&A.

2 Based on 2023 adjusted net income attributable to common shareholders ("adjusted net income"), excluding Corporate costs of $356 million and including holding company interest costs. Adjusted net income is a non-GAAP measure, which does not have standardized meaning under USGAAP. For more information and a reconciliation to the nearest GAAP measure, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2023 MD&A.

## 2023 ADJUSTED NET INCOME[2]

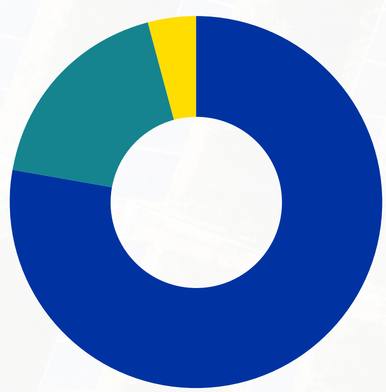
Excluding Corporate costs

### BY BUSINESS SEGMENT



- **54%** Florida electric
- **21%** Canadian electric
- **18%** Gas utilities and infrastructure
- **4%** Other
- **3%** Other electric

### BY REVENUE TYPE



- **78%** Regulated electric
- **18%** Regulated gas
- **4%** Unregulated

# Why Invest in Emera

**With our proven strategy and portfolio of high-quality, regulated utilities, Emera is well positioned to continue delivering cleaner, more reliable energy for our customers while also providing our shareholders with long-term growth in earnings, cash flow and dividends.**

### VISIBLE GROWTH PLAN

**$9B**

capital investment plan[1] through 2026, with $5.4B+ committed to decarbonization and reliability

**75%**

of CapEx plan through 2026 is focused in Florida – the fastest-growing US state

**7% to 8%**

annualized, forecasted rate-base growth through 2026

### STRONG RECORD OF DIVIDEND GROWTH

**5.4%**

annualized dividend growth since 2000

**17 years**

of consecutive dividend growth

**5.7%**

dividend yield[2]

### EFFECTIVE AND COLLABORATIVE REGULATORY ENVIRONMENTS

**Highly rated**

regulatory environments

**96%**

of adjusted net income[3], excluding Corporate costs, derived from our regulated utilities

### STRONG, SUSTAINABLE STRATEGY

**47%**

reduction in $CO_2$ emissions[4], and 77% reduction in coal use[5], since 2005

**18%**

of Board Director Nominees for 2024 identify as members of a diverse group, other than gender[6]

**$12M**

invested in our communities in 2023

**0.25 Lost Time Injury Rate**

down 11% from 2022 (0.28) and a 24% improvement over 5-year average (0.33)

1 Emera's capital investment plan includes $240 million equity investment in 2024.
2 Based on December 29, 2023, share price of $50.30.
3 Based on 2023 adjusted net income, excluding Corporate costs of $356 million and including holding company interest costs. Adjusted net income is a non-GAAP measure, which does not have a standardized meaning under USGAAP. For more information and a reconciliation to the nearest GAAP measure, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2023 MD&A.
4 Undergoing final review and verification
5 As a percentage of total GWh generated compared to 2005 levels. Just 13 per cent of energy generated across Emera comes from coal.
6 One Director Nominee identifies as a racialized person and one Director Nominee identifies as a member of the LGBTQ2SI+ community.

# Emera at a Glance

Data is as of December 31, 2023, unless otherwise indicated.

**From our origins as a single electric utility, Emera has grown into an energy leader serving customers in Canada, the US and the Caribbean. Our companies include electric and natural gas utilities, gas pipelines, and energy marketing and trading operations.**

## HIGHLIGHTS

**$39B**
total assets

**$7.6B**
revenue

**7,300**
employees

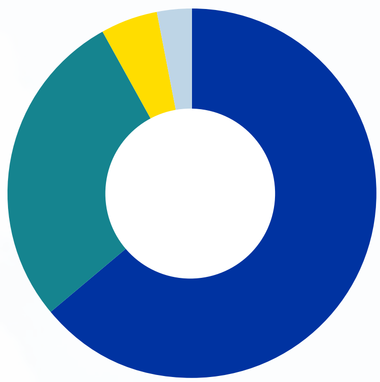
**2.5M**
customers

**6**
electric and natural gas utilities

## ADJUSTED NET INCOME[1]

Excluding Corporate costs

### BY GEOGRAPHY



- **64%** Florida
- **28%** Canada
- **5%** New Mexico
- **3%** Caribbean

1 Based on 2023 adjusted net income, excluding Corporate costs of $356 million and including holding company interest costs. Adjusted net income is a non-GAAP measure, which does not have a standardized meaning under USGAAP. For more information and a reconciliation to the nearest GAAP measure, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2023 MD&A.

## OUR PURPOSE

**Energizing modern life and delivering a cleaner energy future for all.**

## OUR VISION

**To be the energy provider of choice for our customers, the employer of choice for our people and a preferred choice for investors.**

## OUR VALUES

**Our core values shape our culture and guide our work every day.**

- We put safety above all else.
- We put customers at the centre of everything we do.
- We value candour, respect and collaboration.
- We care for each other, the environment and our communities.
- We set a high bar and take on big things.

# OUR STRATEGY

**We're focused on safely delivering cleaner, reliable energy at a pace that's balanced with the cost impacts for our customers.**

## OUR CLIMATE COMMITMENT

**The team across Emera is working together to meet our Climate Commitment goals[1] and our vision to achieve net-zero $CO_2$ emissions by 2050.**

### 2023 PROGRESS

**47% reduction** in $CO_2$ emissions and **77% reduction** in coal use[2]

### 2025 GOAL

**55% reduction** in $CO_2$ emissions

### 2040 GOAL

**80% reduction** in $CO_2$ emissions and **last coal unit retired** no later than 2040

### 2050 VISION

**Net-Zero** $CO_2$ emissions

1 Our Climate Commitment goals are compared to 2005 levels. Achieving our climate goals on these timelines is subject to external factors beyond our control, including government policies and regulatory decisions.
2 Still undergoing review and verification. Reduction in coal use is a percentage of total GWh generated compared to 2005 levels.

# Letter from the Chair and the CEO

**Fellow shareholders,**

We are in an unprecedented time of change and of opportunity. The energy industry worldwide continues to grapple with the complexities of transitioning to cleaner energy while also meeting increasing energy demands. These new realities are amplified by the added pressures of global economic factors such as higher interest rates, increasingly unpredictable weather events and the need to balance the impacts on costs for customers.

Despite these challenges, we continue to advance our strategy of safely delivering cleaner, reliable energy in a way that balances the impacts on costs for customers — and we are making meaningful progress. We are investing in renewable and cleaner generation, reliability and system integrity, infrastructure modernization and expansion, and in new and emerging technologies.

Our work to deliver for our customers across Emera is also driving continued value for our shareholders in the form of sustainable growth in dividends and returns over the long term.

**Jackie Sheppard**
Chair, Emera Inc.
Board of Directors

**Scott Balfour**
President and
CEO, Emera Inc.

> “The Emera Team’s belief in our shared strategy and common values drives our business forward.”

## THE CLEAN ENERGY TRANSITION

There are significant and competing pressures that must be addressed and carefully balanced in order to deliver a successful energy transition. A clean energy future must be achieved in a way that’s balanced with affordability for customers and without sacrificing reliability — all within a system that was built at a time of lower energy demand and with different goals in mind.

As energy policy and objectives continue to evolve, the demand for cleaner, reliable energy increases and the challenges to customer affordability intensify. Each of these critical forces directly impacts the other — affordability is challenged by the need to invest in cleaner energy and reliability. While renewable energy is becoming increasingly cost-effective, our systems were not built to support their intermittency, which means we must invest in backup energy and in grid modernization to support reliability. And all of this requires increased capital investment in an environment where the cost of capital is much higher, inevitably impacting affordability.

In some cases, government policy is enabling the energy transition, with programs such as the *Inflation Reduction Act* in the US and recent federal incentives in Canada, including Investment Tax Credits, grants and loans. Current policy objectives, such as the need to achieve 80 per cent renewable energy and close coal plants in Nova Scotia by 2030, are being augmented with anticipated future policies, including the Environmental Protection Agency Guidelines in the US and Clean Energy Regulations in Canada. As we navigate long-term capital investment decisions under these evolving policy constructs, we are working with governments and regulators to add our voice to these important discussions to help inform policy with the goal of developing the most effective and cost-efficient path forward for customers.

## 2023 HIGHLIGHTS

We are continuing to make progress on this complex energy transition, thanks to the dedicated and highly skilled members of our team across Emera. Their belief in our shared strategy and common values drives our business forward. Last year, we reinforced this commitment by refreshing our company-wide purpose, vision and values — an articulation of why and how we do what we do — fortifying our commitment to delivering for our customers every day. We are working together to energize modern life and deliver a cleaner energy future for all. We strive to be the energy provider of choice for customers, the employer of choice for our people and a preferred choice for investors. We do all this by putting the needs of our customers at the centre of everything we do. We collaborate and care for each other, the environment and our communities — and we’re not afraid to tackle big challenges, including those that arise as we navigate the complexities of the clean energy transition. Above all, we value the safety of our teams and communities.

> "We are continuing to make progress on this complex energy transition, thanks to the dedicated and highly skilled members of our team across Emera."

Despite the economic headwinds faced in 2023, we safely executed on a nearly $3 billion capital program — the largest annual capital program in our history — with a focus on decarbonization and reliability. This investment is driving our progress toward realizing our vision to achieve net-zero $CO_2$ emissions by 2050. As of 2023, we have reduced $CO_2$ emissions by 47 per cent compared to 2005 levels. Some of our accomplishments across Emera in 2023 include:

- Tampa Electric brought four new solar projects into service in 2023, bringing total solar capacity to 1,255 MW — enough to power more than 200,000 homes. Solar energy has saved Tampa Electric customers approximately $200 million in fuel costs over the last five years.
- Tampa Electric reported its best year for reliability, setting all-time records in four of its five main reliability metrics, including a 56 per cent reduction in the average duration of customer outages since 2018.
- Despite the impacts of one hurricane, record low temperatures, wildfires, historic flooding and unprecedented daily lightning strikes, NS Power still improved reliability for customers in 2023. In addition to reducing the average frequency of outages over the last five years, the team also achieved a 36 per cent reduction in the duration[1] of outages over the five-year average.
- The Maritime Link performed well, delivering almost 160 per cent of the contracted energy in 2023, accounting for nearly 20 per cent of NS Power's energy requirements. The Maritime Link achieved 99.9 per cent availability for 2023, putting it in the top 10 per cent of high-voltage direct current links globally.
- At Peoples Gas, the New River, Brightmark and Alliance renewable natural gas (RNG) projects were completed in 2023. These are now online and providing a clean, cost-effective source of energy, while also capturing methane that would otherwise be emitted into the atmosphere.
- New Mexico Gas was recognized by the American Gas Association for best practices on leak management. Its Advanced Mobile Leak Detection technology uses lasers that detect and analyze methane gas emissions. It uses special software to calculate wind speeds and determine the precise location of emissions sources, allowing the team to detect and address leaks more efficiently, reducing the risk of a safety incident.

1 Customer Average Interruption Duration Index (CAIDI), including the impacts of major weather events


- The Barbados Light & Power team achieved record reliability in 2023 with a 10 per cent improvement in intensity (a measure that considers the product of the average interruption duration and frequency rates) compared to 2022 — which was their previous best-performing year. At Grand Bahama Power, the team signed three Independent Power Purchase Agreements to add 14.5 MW of solar to its mix in 2024, while also continuing to advance the development of 5MW of additional solar to be added to its generation fleet in 2025.
- New rates came into effect in two of our utilities in January 2023. At Peoples Gas, the increase is helping us continue to deliver safe, reliable natural gas service to an expanding customer base. At NS Power, the new rate is helping us meet the growing demand for electricity, strengthen reliability and protect our systems against increasingly severe weather as we work to meet government targets for moving off of coal generation.

As we continue working to meet our climate objectives, more than 60 per cent of our $9 billion capital plan through 2026 will be invested in cleaner energy and reliability initiatives across the business.

## SAFETY

The safety of our teams, customers and communities always comes first. We work to continually improve as we strive for an Emera that's predictably safe and where team members are empowered to speak up for safety and know they should only perform a task if they're certain it can be done safely. And 2023 was no exception as we continued to improve on our overall safety performance in the past year.

Our lost time injury rate improved by 24 per cent compared to our average over the last five years, achieving our best-ever level of safety performance.

Our strong safety culture is underpinned by effective safety leadership and robust safety programs. In 2023, we placed even greater focus on reinforcing leadership safety by setting a goal for 75 per cent of the corporate senior management team to complete at least one safety engagement every six months. We were pleased to surpass this goal, achieving 86 per cent.

While we are proud of our achievements in 2023, we know our work to keep each other safe each and every day is never complete.

## FINANCIAL RESULTS

For 2023, we reported annual adjusted earnings[1] of $809 million and adjusted earnings per share (EPS)[1] of $2.96. Adjusted EPS in 2023 was down approximately two per cent from 2022, which was a record earnings year for Emera when you adjust for the $45 million after-tax earnings impact of a litigation settlement received in Q4 2022.

This decrease was primarily due to the impacts of higher interest rates and unfavourable weather conditions in Florida. While our annual results for 2023 were down year-over-year, we continue to build long-term value for our shareholders. We raised our dividend by four per cent in 2023, continuing our more than 17-year history of growing our dividend. And we've delivered annualized dividend growth of 5.4 per cent since 2000.

Across the energy industry, 2023 was not a good year for North American utility stock total returns. In Canada, the TSX Capped Utilities Index underperformed by 11.6 per cent compared to the broader TSX Index. In the US, the utilities index delivered its worst performance in 50 years compared to the S&P 500.

Emera's Total Shareholder Return (TSR) for 2023 was 2.5 per cent, which outperformed both the Canadian and US utility indices. Over the longer term, we delivered 10 per cent annualized TSR over the last 10 years.

With demand for clean, reliable energy on the rise, the drivers for growth remain strong, evidenced by our forecasted 7-8 per cent rate-base growth CAGR over the next three years, as we invest to meet the demands of our customers. We are confident that as we make these customer-focused investments, and as we work to continue to improve our balance sheet, we will also deliver long-term value for Emera's shareholders.

## BOARD CHANGES

We would like to acknowledge long-time Director Andrea Rosen who is stepping down from the Emera Board this year. Since joining the Board in 2007, her leadership experience, financial acumen and experience and knowledge of investment and commercial banking have been of great benefit to Emera. We thank Andrea for her many contributions and wish her continued success.

We are pleased to welcome Brian Porter to the Board. Brian is the former President and Chief Executive Officer of the Bank of Nova Scotia (Scotiabank). His extensive expertise in capital markets and corporate strategy, as well as his experience in driving growth and leading a public company, will bring significant value. Welcome, Brian.

## THANK YOU

At Emera, we believe good strategy starts with a strong team and effective execution — and that we all work better because our strategy and teams are grounded in shared purpose and values. Our people are the driving force behind our shared achievements and are essential to our success.

To the Board of Directors and the entire Emera team, thank you for your ongoing focus on delivering strong results for our customers, communities and shareholders.

To our valued shareholders, thank you for your ongoing confidence in Emera.

**Jackie Sheppard**
Chair, Emera Inc.
Board of Directors

**Scott Balfour**
President and Chief
Executive Officer, Emera Inc.

1 Adjusted net income and adjusted EPS are non-GAAP measures, which do not have standardized meaning under USGAAP. For more information and a reconciliation to the nearest GAAP measure, refer to "Non-GAAP Financial Measures and Ratios" in Emera's Q4 2023 MD&A.

# Financial Review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# Management's Discussion & Analysis

As at February 26, 2024

Management's Discussion & Analysis ("MD&A") provides a review of the results of operations of Emera Incorporated and its consolidated subsidiaries and investments (collectively referred to as "Emera" or the "Company") during the fourth quarter of, and for the full year of, 2023 relative to the same periods in 2022 and selected financial information for 2021; and its financial position as at December 31, 2023 relative to December 31, 2022. The Company's activities are carried out through five reportable segments: Florida Electric Utility, Canadian Electric Utilities, Gas Utilities and Infrastructure, Other Electric Utilities, and Other.

This MD&A should be read in conjunction with the Emera annual audited consolidated financial statements and supporting notes as at and for the year ended December 31, 2023. Emera follows United States Generally Accepted Accounting Principles ("USGAAP" or "GAAP"). Additional information related to Emera, including the Company's Annual Information Form can be found on Sedar+ at www.sedarplus.ca.

The accounting policies used by Emera's rate-regulated entities may differ from those used by Emera's non-rate-regulated businesses with respect to the timing of recognition of certain assets, liabilities, revenues and expenses. At December 31, 2023, Emera's rate-regulated subsidiaries and investments include:

| **Emera Rate-Regulated Subsidiary or Equity Investment** | **Accounting Policies Approved/Examined By** |
|---|---|
| **Subsidiary** | |
| Tampa Electric Company ("TEC") (1) | Florida Public Service Commission ("FPSC") and the Federal Energy Regulatory Commission ("FERC") |
| Nova Scotia Power Inc. ("NSPI") | Nova Scotia Utility and Review Board ("UARB") |
| Peoples Gas System, Inc. ("PGS") (1) | FPSC |
| New Mexico Gas Company, Inc. ("NMGC") | New Mexico Public Regulation Commission ("NMPRC") |
| SeaCoast Gas Transmission, LLC ("SeaCoast") | FPSC |
| Emera Brunswick Pipeline Company Limited ("Brunswick Pipeline") | Canadian Energy Regulator ("CER") |
| Barbados Light & Power Company Limited ("BLPC") | Fair Trading Commission, Barbados ("FTC") |
| Grand Bahama Power Company Limited ("GBPC") | The Grand Bahama Port Authority ("GBPA") |
| **Equity Investments** | |
| NSP Maritime Link Inc. ("NSPML") | UARB |
| Labrador Island Link Limited Partnership ("LIL") | Newfoundland and Labrador Board of Commissioners of Public Utilities |
| Maritimes & Northeast Pipeline Limited Partnership and Maritimes & Northeast Pipeline, LLC ("M&NP") | CER and FERC |
| St. Lucia Electricity Services Limited ("Lucelec") | National Utility Regulatory Commission |

(1) Effective January 1, 2023, Peoples Gas System ceased to be a division of TEC and the gas utility was reorganized, resulting in a separate legal entity called Peoples Gas System, Inc., a wholly owned direct subsidiary of TECO Gas Operations, Inc.

All amounts are in Canadian dollars ("CAD"), except for the Florida Electric Utility, Gas Utilities and Infrastructure, and Other Electric Utilities sections of the MD&A, which are reported in United States dollars ("USD") unless otherwise stated.

## Forward-looking Information

This MD&A contains "forward-looking information" ("FLI") and statements which reflect the current view with respect to the Company's expectations regarding future growth, results of operations, performance, carbon dioxide emissions reduction goals, business prospects and opportunities, and may not be appropriate for other purposes within the meaning of applicable Canadian securities laws. All such information and statements are made pursuant to safe harbour provisions contained in applicable securities legislation. The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecast", "intends", "may", "might", "plans", "projects", "schedule", "should", "targets", "will", "would" and similar expressions are often intended to identify FLI, although not all FLI contains these identifying words. The FLI reflects management's current beliefs and is based on information currently available to Emera's management and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the time at which, such events, performance or results will be achieved.

The FLI is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the FLI. Factors that could cause results or events to differ from current expectations include, without limitation: regulatory and political risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; changes in credit ratings; future dividend growth; timing and costs associated with certain capital investments; expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather risk, including higher frequency and severity of weather events; risk of wildfires; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; inflation risk; counterparty risk; disruption of fuel supply; country risks; supply chain risk; environmental risks; foreign exchange ("FX"); regulatory and government decisions, including changes to environmental legislation, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology ("IT") infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats; market energy sales prices; labour relations; and availability of labour and management resources.

Readers are cautioned not to place undue reliance on FLI, as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the FLI. All FLI in this MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, Emera undertakes no obligation to revise or update any FLI as a result of new information, future events or otherwise.

## Introduction and Strategic Overview

Based in Halifax, Nova Scotia, Emera owns and operates cost-of-service rate-regulated electric and gas utilities in Canada, the United States ("US") and the Caribbean. Cost-of-service utilities provide essential electric and gas services in designated territories under franchises and are overseen by regulatory authorities. Emera's strategic focus continues to be safely delivering cleaner, affordable and reliable energy to its customers.

The majority of Emera's investments in rate-regulated businesses are located in Florida with other investments in Nova Scotia, New Mexico and the Caribbean. Emera's portfolio of regulated utilities provides reliable earnings, cash flow and dividends. Earnings opportunities in regulated utilities are generally driven by the magnitude of net investment in the utility (known as "rate base"), and the amount of equity in the capital structure and the return on that equity ("ROE") as approved through regulation. Earnings are also affected by sales volumes and operating expenses.

Emera's capital investment plan is approximately $9 billion over the 2024 through 2026 period with approximately $2 billion of additional potential capital investments over the same period. The capital investment plan and additional potential capital result in an anticipated compound annual rate base growth in the range of approximately 7 per cent to 8 per cent through 2026. The capital investment plan includes significant investments across the portfolio in renewable and cleaner generation, reliability and system integrity investments, infrastructure modernization, infrastructure expansion to meet the needs of new and existing customers, and technologies to better support the business and customer experiences. It is anticipated that approximately 75 per cent of Emera's $9 billion capital investment plan over the 2024 through 2026 period will be made in Florida.

Emera's capital investment plan is being funded primarily through internally generated cash flows, debt raised at the operating company level consistent with regulated capital structures, equity, and select asset sales. Generally, equity requirements in support of the Company's capital investment plan are expected to be funded through the issuance of preferred equity and the issuance of common equity through Emera's dividend reinvestment plan ("DRIP") and at-the-market program ("ATM program"). Maintaining investment-grade credit ratings is a priority of the Company.

Emera has provided annual dividend growth guidance of four to five per cent through 2026. The Company targets a long-term dividend payout ratio of adjusted net income of 70 to 75 per cent and, while the payout ratio is likely to exceed that target through and beyond the forecast period, it is expected to return to that range over time. For further information on the non-GAAP measure "Dividend Payout Ratio of Adjusted Net Income", refer to the "Non-GAAP Financial Measures and Ratios" section.

Seasonal patterns and other weather events affect demand and operating costs. Similarly, mark-to-market ("MTM") adjustments and foreign currency exchange can have a material impact on financial results for a specific period. Emera's consolidated net income and cash flows are impacted by movements in the USD relative to the CAD. Emera may hedge both transactional and translational exposure. These impacts, as well as the timing of capital investments and other factors, mean results in any one quarter are not necessarily indicative of results in any other quarter, or for the year as a whole.

Energy markets worldwide are experiencing significant change and Emera is well-positioned to continue to respond to shifting customer demands and meet the challenges of digitization, decarbonization and decentralized generation, within complex regulatory environments.

Customers depend on energy and are looking for more choice, better control, and greater reliability. The costs of decentralized generation and storage have become more competitive and advancing technologies are transforming how utilities operate and interact with customers. Concurrently, climate change and the increased frequency of extreme weather events are shaping government energy policy. This is also creating a need to replace aging infrastructure and make investments to protect and harden energy systems to deliver energy reliability and system resiliency. These factors combined with inflation, higher interest rates and higher cost of capital place increased pressure on energy costs, and thus customer rates, at a time when affordability is a challenge.

Emera's strategy is centered on delivering value for customers, and in doing so creating value for shareholders. This includes:

- investing in cleaner and renewable sources of energy, in the related transmission assets, and in energy storage needed to support intermittent renewables;
- supporting increasing demand from customers and the ongoing electrification of other sectors;
- improving system reliability and resiliency, including replacing aging infrastructure and expanding systems to service new customers; and
- investing in new internal and customer-facing technologies for improved cost efficiency and better customer experiences.

Building on its decarbonization progress, Emera is continuing its efforts by establishing clear carbon reduction goals and a vision to achieve net-zero carbon dioxide emissions by 2050.

This vision is inspired by Emera's strong track record, the Company's experienced team, and a visible path to Emera's interim carbon goals. With existing technologies and resources, and subject to supportive government and regulatory decisions, Emera is working to achieve the following goals compared to corresponding 2005 levels:

- A 55 per cent reduction in carbon dioxide emissions by 2025.
- The retirement of Emera's last existing coal unit no later than 2040.
- An 80 per cent reduction in carbon dioxide emissions by 2040.

Achieving the above climate goals on these timelines is subject to the Company's regulatory obligations and other external factors beyond Emera's control.

Emera seeks to deliver on its Climate Commitment while maintaining its focus on investing in reliability and staying focused on the cost impacts for customers. Emera is also committed to identifying emerging technologies and continuing to work constructively with policymakers, regulators, partners, investors and customers to achieve these goals and realize its net-zero vision.

Emera is committed to world-class safety, operational excellence, good governance, excellent customer service, reliability, being an employer of choice, and building constructive relationships.

## Non-GAAP Financial Measures and Ratios

Emera uses financial measures and ratios that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and ratios are calculated by adjusting certain GAAP measures for specific items. Management believes excluding these items better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the business. These measures and ratios are discussed and reconciled below.

### Adjusted Net Income Attributable to Common Shareholders, Adjusted Earnings (Loss) Per Common Share ("EPS") – Basic and Dividend Payout Ratio of Adjusted Net Income

Emera calculates an adjusted net income attributable to common shareholders ("adjusted net income") measure by excluding the effect of MTM adjustments, the GBPC impairment charge in 2022, and the impact of the 2022 NSPML unrecoverable costs.

Management believes excluding from net income the effect of MTM valuations and changes thereto, until settlement, better aligns the intent and financial effect of these contracts with the underlying cash flows, and therefore excludes MTM adjustments for evaluation of performance and incentive compensation. The MTM adjustments are related to the following:

- held-for-trading ("HFT") commodity derivative instruments, including adjustments related to the price differential between the point where natural gas is sourced and where it is delivered, and the related amortization of transportation capacity recognized as a result of certain Emera Energy marketing and trading transactions;
- the business activities of Bear Swamp Power Company LLC ("Bear Swamp") included in Emera's equity income;
- equity securities held in BLPC and Emera Energy; and
- FX hedges entered into to hedge USD denominated operating unit earnings exposure.

For further detail on these MTM adjustments, refer to the "Consolidated Financial Review", "Financial Highlights – Other Electric Utilities", and "Financial Highlights – Other" sections.

In Q4 2022, the Company recognized a $73 million non-cash goodwill impairment charge related to GBPC due to a decline in the fair value ("FV") of the reporting unit driven by the effects of macro-economic factors on the discount rate calculation. Management believes excluding from net income the effect of this charge better distinguishes ongoing operations of the business and allows investors to better understand and evaluate the Company. For further details on the GBPC impairment charge, refer to "Significant Items Impacting Earnings", and "Financial Highlights – Other Electric Utilities" sections.

In February 2022, the UARB issued a decision to disallow recovery of $9 million in costs ($7 million after-tax) included in NSPML's final capital cost application. The after-tax unrecoverable costs were recognized in "Income from equity investments" in Emera's Consolidated Statements of Income. Management believes excluding these unrecoverable costs from the calculation of adjusted net income better reflects the underlying operations in the period. For further details on the 2022 NSPML unrecoverable costs, refer to the "Financial Highlights – Canadian Electric Utilities" section.

Adjusted EPS – basic and dividend payout ratio of adjusted net income are non-GAAP ratios which are calculated using adjusted net income, as described above. For further details on dividend payout ratio of adjusted net income, see the "Dividend Payout Ratio" section.

Emera calculates adjusted net income for the Canadian Electric Utilities, Other Electric Utilities, and Other segments. Reconciliation to the nearest GAAP measure is included in each segment. Refer to "Financial Highlights – Canadian Electric Utilities", "Financial Highlights – Other Electric Utilities" and "Financial Highlights – Other" sections.

The following reconciles net income attributable to common shareholders to adjusted net income:

| For the<br>millions of dollars (except per share amounts) | Three months ended December 31<br>**2023** | 2022 | Year ended December 31<br>**2023** | 2022 | 2021 |
|---|---|---|---|---|---|
| Net income attributable to common shareholders | **$ 289** | $ 483 | **$ 978** | $ 945 | $ 510 |
| MTM gain (loss), after-tax (1) | **114** | 307 | **169** | 175 | (213) |
| GBPC impairment charge | **–** | (73) | **–** | (73) | – |
| NSPML unrecoverable costs (2) | **–** | – | **–** | (7) | – |
| Adjusted net income | **$ 175** | $ 249 | **$ 809** | $ 850 | $ 723 |
| EPS – basic | **$ 1.04** | $ 1.80 | **$ 3.57** | $ 3.56 | $ 1.98 |
| Adjusted EPS – basic | **$ 0.63** | $ 0.93 | **$ 2.96** | $ 3.20 | $ 2.81 |

(1) Net of income tax expense of $44 million for the three months ended December 31, 2023 (2022 – $124 million expense) and $68 million expense for the year ended December 31, 2023 (2022 – $73 million expense) (2021 – $86 million recovery).
(2) Emera accounts for NSPML as an equity investment and therefore the after-tax unrecoverable costs were recorded in "Income from equity investments" on Emera's Consolidated Statements of Income.

## EBITDA and Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("EBITDA") and adjusted EBITDA are non-GAAP financial measures used by Emera. These financial measures are used by numerous investors and lenders to better understand cash flows and credit quality. EBITDA is useful to assess Emera's operating performance and indicates the Company's ability to service or incur debt, invest in capital, and finance working capital requirements.

Similar to adjusted net income calculations described above, adjusted EBITDA represents EBITDA absent the income effect of MTM adjustments, the 2022 GBPC impairment charge and the 2022 NSPML unrecoverable costs.

The following is a reconciliation of net income to EBITDA and Adjusted EBITDA:

| For the<br>millions of dollars | Three months ended December 31<br>**2023** | 2022 | Year ended December 31<br>**2023** | 2022 | 2021 |
|---|---|---|---|---|---|
| Net income (1) | **$ 307** | $ 499 | **$ 1,045** | $ 1,009 | $ 561 |
| Interest expense, net | **241** | 206 | **925** | 709 | 611 |
| Income tax expense (recovery) | **51** | 154 | **128** | 185 | (6) |
| Depreciation and amortization | **264** | 254 | **1,049** | 952 | 902 |
| EBITDA | **$ 863** | $ 1,113 | **$ 3,147** | $ 2,855 | $ 2,068 |
| MTM gain (loss), before-tax | **158** | 431 | **237** | 248 | (299) |
| GBPC impairment charge | **–** | (73) | **–** | (73) | – |
| NSPML unrecoverable costs (2) | **–** | – | **–** | (7) | – |
| Adjusted EBITDA | **$ 705** | $ 755 | **$ 2,910** | $ 2,687 | $ 2,367 |

(1) Net income is before Non-controlling interest in subsidiaries and Preferred stock dividends.
(2) Emera accounts for NSPML as an equity investment and therefore the after-tax unrecoverable costs were recorded in "Income from equity investments" on Emera's Consolidated Statements of Income.

# Consolidated Financial Review

## SIGNIFICANT ITEMS AFFECTING EARNINGS

### 2023

#### Earnings Impact of MTM Gain, After-Tax

MTM gain, after-tax decreased $193 million to $114 million in Q4 2023, compared to $307 million in Q4 2022 primarily due to unfavourable changes in existing positions, partially offset by higher amortization of gas transportation assets in 2022 at Emera Energy Services ("EES"). For the year ended December 31, 2023, MTM gain, after-tax decreased $6 million to $169 million compared to $175 million for the same period in 2022 primarily due to higher amortization of gas transportation assets at EES, partially offset by favourable changes in existing positions at EES and gains on Corporate FX hedges.

### 2022

#### GBPC Impairment Charge

In Q4 2022, Emera recognized a goodwill impairment charge of $73 million ($0.27 per common share) for GBPC due to a decline in the FV of the reporting unit driven by the effects of macro-economic factors on discount rate calculations. This non-cash charge was recorded in "GBPC Impairment charge" on the Consolidated Statements of Income and reduced the GBPC goodwill balance to nil. For further details, refer to note 22 in the consolidated financial statements.

#### TECO Guatemala Holdings ("TGH") International Arbitration and Award

In Q4 2022, a payment of $63 million ($45 million after tax and legal costs, or $0.17 per common share), was made by the Republic of Guatemala to TECO Energy in satisfaction of the second and final award issued by the International Centre of the Settlement of Investment Disputes tribunal regarding a dispute over an investment of TGH, a wholly owned subsidiary of TECO Energy. The payment was recognized in 'Other income, net" on the Consolidated Statements of Income. For further details, refer to note 8 in the consolidated financial statements.

## CONSOLIDATED FINANCIAL HIGHLIGHTS

| For the<br>millions of dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| **Adjusted net income** | **2023** | 2022 | **2023** | 2022 | 2021 |
| Florida Electric Utility | **$ 115** | $ 124 | **$ 627** | $ 596 | $ 462 |
| Canadian Electric Utilities | **68** | 46 | **247** | 222 | 241 |
| Gas Utilities and Infrastructure | **59** | 72 | **214** | 221 | 198 |
| Other Electric Utilities | **4** | 8 | **35** | 29 | 20 |
| Other | **(71)** | (1) | **(314)** | (218) | (198) |
| Adjusted net income | **$ 175** | $ 249 | **$ 809** | $ 850 | $ 723 |
| MTM gain (loss), after-tax | **114** | 307 | **169** | 175 | (213) |
| GBPC impairment charge | **–** | (73) | **–** | (73) | – |
| NSPML unrecoverable costs | **–** | – | **–** | 7 | – |
| Net income attributable to common shareholders | **$ 289** | $ 483 | **$ 978** | $ 945 | $ 510 |

The following table highlights the significant changes in adjusted net income from 2022 to 2023:

| For the<br>millions of dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Adjusted net income – 2022** | **$ 249** | **$ 850** |
| **Operating Unit Performance** | | |
| Increased earnings at NSPI due to new base rates and increased sales volumes, partially offset by higher operating, maintenance and general expenses ("OM&G"), interest expense and depreciation | 17 | 10 |
| Increased income from equity investments at NSPML quarter-over-quarter primarily due to the Maritime Link holdback (the "holdback") recognized in Q4 2022. Year-over-year also due to the partial reversal in Q3 2023 of the holdback recognized in 2022 | 4 | 10 |
| Decreased earnings quarter-over-quarter at TEC due to increased interest expense, depreciation, state and municipal taxes, unfavourable weather, and higher OM&G, partially offset by new base rates and customer growth driving higher sales volumes. Increased earnings year-over-year due to new base rates, the impact of a weaker CAD and customer growth, partially offset by higher interest expense, depreciation, state and municipal taxes, and OM&G, and unfavourable weather | (9) | 31 |
| Decreased earnings quarter-over-quarter at NMGC primarily due to lower asset optimization revenues and higher OM&G, partially offset by new base rates. Increased earnings year-over-year due to new base rates, partially offset by higher OM&G and interest expense | (11) | 12 |
| Decreased earnings at EES due to more favourable market conditions in 2022 | (21) | (22) |
| **Corporate** | | |
| Decreased OM&G, pre-tax, due to timing of long-term compensation and related hedges | 13 | 10 |
| Increased interest expense, pre-tax, due to higher interest rates and higher debt levels | (9) | (51) |
| Decreased income tax recovery quarter-over-quarter primarily due to the impact of effective state tax rates | (10) | 2 |
| TGH award, after tax and legal costs, in Q4 2022. Refer to the "Significant Items Affecting Earnings" section | (45) | (45) |
| **Other Variances** | (3) | 2 |
| **Adjusted net income – 2023** | **$ 175** | **$ 809** |

For further details of reportable segments contributions, refer to the "Financial Highlights" section.

| For the<br>millions of dollars | **2023** | 2022 | Year ended<br>December 31<br>2021 |
|---|---|---|---|
| Operating cash flow before changes in working capital | **$ 2,336** | $ 1,147 | $ 1,337 |
| Change in working capital | **(95)** | (234) | (152) |
| Operating cash flow | **$ 2,241** | $ 913 | $ 1,185 |
| Investing cash flow | **$ (2,917)** | $ (2,569) | $ (2,332) |
| Financing cash flow | **$ 939** | $ 1,555 | $ 1,311 |

For further discussion of cash flow, refer to the "Consolidated Cash Flow Highlights" section.

| As at<br>millions of dollars | **2023** | 2022 | December 31<br>2021 |
|---|---|---|---|
| Total assets | **$ 39,480** | $ 39,742 | $ 34,244 |
| Total long-term debt (including current portion) | **$ 18,365** | $ 16,318 | $ 14,658 |

## CONSOLIDATED INCOME STATEMENT HIGHLIGHTS

| For the millions of dollars (except per share amounts) | Three months ended December 31 2023 | 2022 | Variance | Year ended December 31 2023 | 2022 | Variance | Year ended December 31 2021 |
|---|---|---|---|---|---|---|---|
| Operating revenues | **$ 1,972** | $ 2,358 | $ (386) | **$ 7,563** | $ 7,588 | $ (25) | $ 5,765 |
| Operating expenses | **1,467** | 1,638 | 171 | **5,769** | 5,959 | 190 | 4,835 |
| Income from operations | **$ 505** | $ 720 | $ (215) | **$ 1,794** | $ 1,629 | $ 165 | $ 930 |
| Other income, net | **$ 51** | $ 102 | $ (51) | **$ 158** | $ 145 | $ 13 | $ 93 |
| Interest expense, net | **$ 241** | $ 206 | $ (35) | **$ 925** | $ 709 | $ (216) | $ 611 |
| Net income attributable to common shareholders | **$ 289** | $ 483 | $ (194) | **$ 978** | $ 945 | $ 33 | $ 510 |
| Adjusted net income | **$ 175** | $ 249 | $ (74) | **$ 809** | $ 850 | $ (41) | $ 723 |
| Weighted average shares of common stock outstanding (in millions) (1) | **277.7** | 269.0 | 8.7 | **273.6** | 265.5 | 8.1 | 257.2 |
| EPS – basic | **$ 1.04** | $ 1.80 | $ (0.76) | **$ 3.57** | $ 3.56 | $ 0.01 | $ 1.98 |
| EPS – diluted | **$ 1.04** | $ 1.80 | $ (0.76) | **$ 3.57** | $ 3.55 | $ 0.02 | $ 1.98 |
| Adjusted EPS – basic | **$ 0.63** | $ 0.93 | $ (0.30) | **$ 2.96** | $ 3.20 | $ (0.24) | $ 2.81 |
| Adjusted EBITDA | **$ 705** | $ 755 | $ (50) | **$ 2,910** | $ 2,687 | $ 223 | $ 2,367 |
| Dividends per common share declared | **$ 0.7175** | $ 0.6900 | $ 0.0275 | **$ 2.7875** | $ 2.6775 | $ 0.1100 | $ 2.5750 |
| Dividends per first preferred shares declared: | | | | | | | |
| Series A | | | | **$ 0.5456** | $ 0.5456 | $ – | $ 0.5456 |
| Series B | | | | **$ 1.5583** | $ 0.6869 | $ 0.8714 | $ 0.4873 |
| Series C | | | | **$ 1.2873** | $ 1.1802 | $ 0.1071 | $ 1.1802 |
| Series E | | | | **$ 1.1250** | $ 1.1250 | $ – | $ 1.1250 |
| Series F | | | | **$ 1.0505** | $ 1.0505 | $ – | $ 1.0505 |
| Series H | | | | **$ 1.3140** | $ 1.2250 | $ 0.0890 | $ 1.2250 |
| Series J | | | | **$ 1.0625** | $ 1.0625 | $ – | $ 0.6470 |
| Series L | | | | **$ 1.1500** | $ 1.1500 | $ – | $ 0.1638 |

(1) Effective February 10, 2022, deferred share units are no longer able to be settled in shares and are therefore excluded from weighted average shares of common stock outstanding.

### Operating Revenues

For Q4 2023, operating revenues decreased $386 million compared to Q4 2022 and, excluding decreased MTM gains of $286 million, decreased $100 million. The decrease was due to lower fuel revenues at NMGC, TEC, and NSPI; decreased marketing and trading margin at EES; lower asset optimization revenue at NMGC; and unfavourable weather at TEC. These decreases were partially offset by new base rates at TEC, NSPI and NMGC; storm cost recovery surcharge revenue at TEC; customer growth at TEC and NSPI; and favourable weather at NSPI.

For the year ended December 31, 2023, operating revenues decreased $25 million compared to 2022 and, excluding decreased MTM gains of $62 million, increased $37 million. The increase was due to new base rates at TEC, NSPI and NMGC; the impact of a weaker CAD; storm cost recovery surcharge revenue at TEC; and customer growth at TEC and NSPI. These increases were partially offset by lower fuel revenues at NMGC, TEC, NSPI, PGS and BLPC; lower off-system sales at PGS; a change in fuel cost recovery methodology for an industrial customer at NSPI; and decreased marketing and trading margin at EES.

### Operating Expenses

For Q4 2023, operating expenses decreased $171 million compared to Q4 2022 and excluding the 2022 GBPC impairment charge of $73 million, decreased $98 million. For the year ended December 31, 2023, operating expenses decreased $190 million compared to 2022 and excluding the 2022 GBPC impairment charge of $73 million, decreased $117 million. The decreases in both periods were due to lower fuel expenses at TEC, NMGC, and PGS; partially offset by higher OM&G at TEC due to storm restoration costs recognized related to the storm cost recovery surcharge revenue, and at NSPI due to higher power generation and transmission and distribution field services cost. Year-over-year the decrease was also due to a change in fuel cost recovery for an industrial customer at NSPI, partially offset by the impact of a weaker CAD and the recognition of the Nova Scotia Renewable Electricity Regulations ("RER") penalty at NSPI.

### Other Income, net

For Q4 2023, other income, net decreased $51 million compared to Q4 2022, primarily due to the TGH award in Q4 2022. For the year ended December 31, 2023, other income, net increased $13 million compared to 2022, primarily due to increased FX gains in 2023; higher interest income primarily at TEC; and higher pension non-current service cost recovery, partially offset by the TGH award in 2022.

### Interest Expense, net

Interest expense, net for Q4 2023 increased $35 million, and for the year ended December 31, 2023 increased $216 million compared to the same periods in 2022. The increases in both periods were due to higher interest rates; higher borrowings to support capital investments and ongoing operations; and the impact of a weaker CAD.

### Net Income and Adjusted Net Income

Net income attributable to common shareholders for Q4 2023, compared to Q4 2022, was unfavourably impacted by the $193 million decrease in MTM gains, after-tax, and favourably impacted by the $73 million GBPC impairment charge from 2022. Excluding these changes, adjusted net income decreased $74 million. This was primarily due to the TGH award in Q4 2022; decreased earnings at EES, NMGC and TEC; lower Corporate income tax recovery; and increased Corporate interest expense. These were partially offset by increased earnings at NSPI and NSPML; and decreased Corporate OM&G due to the timing of long-term compensation and related hedges.

Net income attributable to common shareholders for the year ended 2023, as compared to the same period in 2022, was unfavourably impacted by the $6 million decrease in MTM gains, after-tax, and favourably impacted by the $73 million GBPC impairment charge and the $7 million in NSPML unrecoverable costs from 2022. Excluding these changes, adjusted net income decreased $41 million. The decrease was primarily due to increased Corporate interest expense due to higher interest rates and increased total debt; the TGH award in Q4 2022; and decreased earnings at EES. These were partially offset by increased earnings at TEC, NMGC, NSPI and NSPML.

### EPS and Adjusted EPS – Basic

EPS and Adjusted EPS – basic were lower for Q4 2023 due to the increase in weighted average shares of common stock outstanding and decreased earnings as discussed above.

EPS – basic was higher for the year ended December 31, 2023, due to the impact of higher earnings as discussed above. Adjusted EPS – basic was lower for the year ended December 31, 2023 due to the increase in weighted average shares of common stock outstanding and decreased adjusted earnings, as discussed above.

### Effect of Foreign Currency Translation

Emera operates in Canada, the United States and various Caribbean countries and, as such, generates revenues and incurs expenses denominated in local currencies which are translated into CAD for financial reporting. Changes in translation rates, particularly in the value of the USD against the CAD, can positively or adversely affect results.

Results of foreign operations are translated at the weighted average rate of exchange, and assets and liabilities of foreign operations are translated at period end rates. The relevant CAD/USD exchange rates for 2023 and 2022 are as follows:

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2023** | 2022 | **2023** | 2022 |
| Weighted average CAD/USD | **$ 1.36** | $ 1.37 | **$ 1.35** | $ 1.34 |
| Period end CAD/USD exchange rate | **$ 1.32** | $ 1.35 | **$ 1.32** | $ 1.35 |

The table below includes Emera's significant segments whose contributions to adjusted net income are recorded in USD currency:

| For the<br>millions of USD | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2023** | 2022 | **2023** | 2022 |
| Florida Electric Utility | **$ 85** | $ 91 | **$ 466** | $ 458 |
| Gas Utilities and Infrastructure (1) | **41** | 45 | **142** | 143 |
| Other Electric Utilities | **3** | 7 | **26** | 23 |
| Other segment (2) | **(18)** | 30 | **(95)** | (50) |
| **Total** (3) | **$ 111** | $ 173 | **$ 539** | $ 574 |

(1) Includes USD net income from PGS, NMGC, SeaCoast and M&NP.
(2) Includes Emera Energy's USD adjusted net income from EES, Bear Swamp and interest expense on Emera Inc.'s USD denominated debt.
(3) Excludes $73 million USD in MTM gain, after-tax, for the three months ended December 31, 2023 (2022 – $222 million USD MTM gain, after-tax) and MTM gain, after-tax of $116 million USD for the year ended December 31, 2023 (2022 – $130 million USD MTM gain, after-tax) and the GBPC impairment charge of nil for the three months and year ended December 31, 2023 (2022 – $54 million USD).

The translation impact of the change in FX rates on foreign denominated earnings increased net income by $13 million in Q4 2023 and $46 million for the year ended December 31, 2023, compared to the same periods in 2022. The translation impact of the change in FX rates on foreign denominated earnings decreased adjusted net income by $3 million in Q4 2023 and increased adjusted net income by $20 million for the year ended December 31, 2023 compared to the same periods in 2022. Impacts of the changes in the translation of the CAD include the impacts of Corporate FX hedges used to mitigate translation risk of USD earnings in the Other segment.

## Business Overview and Outlook

Emera's 2023 results were impacted by macroeconomic conditions, specifically higher interest rates as well as other impacts of inflation. These macroeconomic conditions are likely to continue for the near term. For information on general economic risk, including interest rate and inflation risk, refer to the "Enterprise Risk and Risk Management – General Economic Risk" section.

### FLORIDA ELECTRIC UTILITY

Florida Electric Utility consists of TEC, a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity, serving customers in West Central Florida. TEC has $12 billion USD of assets and approximately 840,000 customers at December 31, 2023. TEC owns 6,433 megawatts ("MW") of generating capacity, of which 74 per cent is natural gas fired, 19 per cent is solar and 7 per cent is coal. TEC owns 2,192 kilometres of transmission facilities and 20,299 kilometres of distribution facilities. TEC meets the planning criteria for reserve capacity established by the FPSC, which is a 20 per cent reserve margin over firm peak demand.

TEC's approved regulated ROE range is 9.25 per cent to 11.25 per cent, based on an allowed equity capital structure of 54 per cent. An ROE of 10.20 per cent is used for the calculation of the return on investments for clauses.

TEC anticipates earning towards the lower end of the ROE range in 2024 but expects earnings to be higher than 2023. Normalizing 2023 for weather, TEC sales volumes in 2024 are projected to be higher than 2023 due to customer growth. TEC expects customer growth rates in 2024 to be comparable to 2023, reflective of the expected economic growth in Florida.

On February 1, 2024, TEC notified the FPSC of its intent to seek a base rate increase effective January 2025, reflecting a revenue requirement increase of approximately $290 to $320 million USD and additional adjustments of approximately $100 million USD and $70 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 numerous other resiliency and reliability projects. The filing range amounts are estimates until TEC files its detailed case in April 2024. The FPSC is scheduled to hear the case in Q3 2024 with a decision expected by the end of 2024.

On August 16, 2023, TEC filed a petition to implement the 2024 Generation Base Rate Adjustment provisions pursuant to the 2021 rate case settlement agreement. Inclusive of TEC's ROE adjustment, the increase of $22 million USD was approved by the FPSC on November 17, 2023.

On January 23, 2023, TEC petitioned the FPSC for recovery of the storm reserve regulatory asset and the replenishment of the balance in the storm reserve to the approved storm reserve level of $56 million USD, for a total of $131 million USD. The storm cost recovery surcharge was approved by the FPSC on March 7, 2023, and TEC began applying the surcharge in April 2023. Subsequently, on November 9, 2023, the FPSC approved TEC's petition, filed on August 16, 2023, to update the total storm cost collection to $134 million USD. It also changed the collection of the expected remaining balance of $29 million USD as of December 31, 2023, from over the first three months of 2024 to over the 12 months of 2024. The storm recovery is subject to review of the underlying costs for prudency and accuracy by the FPSC and issuance of an order by the FPSC is expected by Q3 2024.

In Q3 2023, TEC was impacted by Hurricane Idalia. The related storm restoration costs were approximately $35 million USD, which were charged to the storm reserve regulatory asset, resulting in minimal impact to earnings. TEC will determine the timing of the request for recovery of Hurricane Idalia costs at a future time.

On January 23, 2023, TEC requested an adjustment to its fuel charges to recover the 2022 fuel under-recovery of $518 million USD over a period of 21 months. The request also included an adjustment to 2023 projected fuel costs to reflect the reduction in natural gas prices since September 2022 for a projected reduction of $170 million USD for the balance of 2023. The changes were approved by the FPSC on March 7, 2023, and were effective beginning on April 1, 2023.

In 2024, capital investment in the Florida Electric Utility segment is expected to be $1.3 billion USD (2023 – $1.3 billion USD), including allowance for funds used during construction ("AFUDC"). Capital projects include solar investments, grid modernization, storm hardening investments and building resilience.

## CANADIAN ELECTRIC UTILITIES

Canadian Electric Utilities includes NSPI and ENL. NSPI is a vertically integrated regulated electric utility engaged in the generation, transmission and distribution of electricity and the primary electricity supplier to customers in Nova Scotia. ENL is a holding company with equity investments in NSPML and LIL: two transmission investments related to the development of an 824 MW hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador.

### NSPI

With $7.2 billion of assets and approximately 549,000 customers, NSPI owns 2,422 MW of generating capacity, of which 44 per cent is coal and/or oil-fired; 28 per cent is natural gas and/or oil; 19 per cent is hydro, wind, or solar; 7 per cent is petroleum coke ("petcoke") and 2 per cent is biomass-fueled generation. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPPs") and community feed-in tariff ("COMFIT") participants, which own 532 MW of capacity. NSPI also has rights to 153 MW of Maritime Link capacity, representing Nalcor Energy's ("Nalcor") Nova Scotia Block ("NS Block") delivery obligations, as discussed below. NSPI owns approximately 5,000 kilometres of transmission facilities and 28,000 kilometres of distribution facilities.

Nalcor is obligated to provide NSPI with approximately 900 Gigawatt hours ("GWh") of energy annually over 35 years. In addition, for the first five years of the NS Block, Nalcor is obligated to provide approximately 240 GWh of additional energy from the Supplemental Energy Block transmitted through the Maritime Link. NSPI has the option of purchasing additional market-priced energy from Nalcor through the Energy Access Agreement. The Energy Access Agreement enables NSPI to access a market-priced bid from Nalcor for up to 1.8 Terawatt hours ("TWh") of energy in any given year and, on average, 1.2 TWh of energy per year through August 31, 2041.

NSPI's approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 40 per cent of approved rate base.

NSPI expects earnings and sales volumes to be higher in 2024 than 2023 but anticipates earning below its allowed ROE range in 2024.

On January 29, 2024, NSPI applied to the UARB for approval of a structure that would begin to recover the outstanding Fuel Adjustment Mechanism ("FAM") balance. As part of the application, NSPI requested approval for the sale of $117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation, with the proceeds paid to NSPI upon approval. NSPI has requested approval to collect from customers the amortization and financing costs of $117 million on behalf of Invest Nova Scotia over a 10-year period, and remit those amounts to Invest Nova Scotia as collected, reducing short-term customer rate increases relative to the currently established FAM process. If approved, this portion of the FAM regulatory asset would be removed from the Consolidated Balance Sheets and NSPI would collect the balance on behalf of Invest Nova Scotia in NSPI rates beginning in 2024. A decision is expected in the first half of 2024. It is anticipated that NSPI will apply to the UARB later in 2024 to collect additional under-recovered fuel amounts in 2025 or future periods, subject to the approval of the UARB.

On October 31, 2023, NSPI submitted an application to the UARB to defer $24 million in incremental operating costs incurred during Hurricane Fiona storm restoration efforts in September 2022. NSPI is seeking amortization of the costs over a period to be approved by the UARB during a future rate setting process. At December 31, 2023, the $24 million is deferred to "Other long-term assets", pending UARB approval. A decision is expected from the UARB in 2024.

On September 16, 2023, Nova Scotia was struck by post-tropical storm Lee and as a result, approximately 280,000 customers lost power. The total cost of storm restoration was $19 million, with $9 million charged to "OM&G", $5 million capitalized to property, plant and equipment ("PP&E) and $5 million deferred to the UARB approved storm rider. The storm rider, for each of 2023, 2024, and 2025, allows NSPI to apply to the UARB for deferral and recovery of expenses if major storm restoration expenses exceed approximately $10 million in any given year. The application for deferral of the storm rider is made in the year following the year of the incurred costs, with recovery beginning in the year after the application.

On February 2, 2023, the UARB approved the General Rate Application settlement agreement between NSPI, key customer representatives and participating interest groups. This resulted in average customer rate increases of 6.9 per cent effective on February 2, 2023, and a further average increase of 6.5 per cent on January 1, 2024, with any under or over-recovery of fuel costs addressed through the UARB's established FAM process. It also established a storm rider, described above, and a demand-side management rider. On March 27, 2023, the UARB issued a final order approving the electricity rates effective on February 2, 2023.

In 2024, capital investment, including AFUDC, is expected to be $435 million (2023 – $451 million). NSPI is primarily investing in capital projects required to support power system reliability and reliable service for customers.

## Environmental Legislation and Regulations

NSPI is subject to environmental laws and regulations set by both the Government of Canada and the Province of Nova Scotia (the "Province"). NSPI continues to work with both levels of government to comply with these laws and regulations to maximize efficiency of emission control measures and minimize customer cost. NSPI anticipates that costs prudently incurred to achieve legislated compliance will be recoverable under NSPI's regulatory framework. NSPI faces risks associated with achieving climate-related and environmental legislative requirements, including the risk of non-compliance, which could adversely affect NSPI's operations and financial performance. For further discussion on these risks and environmental legislation and regulations, refer to the "Enterprise Risk and Risk Management" section. Recent developments related to provincial and federal environmental laws and regulations are outlined below.

***Clean Electricity Solutions Task Force:***

The Clean Electricity Solutions Task Force (the "Task Force") was created by the Province in April 2023 to advise the provincial government on Nova Scotia's transition away from coal to more renewable sources of energy. On February 23, 2024, the Task Force released its report and recommendations, based on engagement with stakeholders, including NSPI. The Task Force report focuses on findings related to system operations, regulatory oversight, reliability, transmission and affordability. The Task Force announced a number of recommendations, including a strengthening of the authority and independence of the regulator and the establishment of an independent system operator, in order to support the continuing transition to clean energy and the achievement of federal and provincial clean energy goals and legislation. The Province announced they intend to accept these recommendations and will table enabling legislation in its upcoming session which starts February 27, 2024.

***RER:***

On April 6, 2023, the Province levied a $10 million penalty on NSPI for non-compliance with the RER compliance period ending in 2022. The penalty was recorded in "OM&G" on the Consolidated Statements of Income. On May 26, 2023, NSPI initiated an appeal of the penalty through a proceeding with the UARB, as permitted under the RER. On October 12, 2023, the UARB decided that it will hear the appeal by giving due deference to the Province's decision but permitting the filing of new evidence to support the parties' positions. The hearing for the matter is scheduled for June 2024 and a decision is expected before the end of 2024.

***Carbon Pricing Regulations:***

In November 2022, the Province enacted amendments to the Environment Act which provided the framework for Nova Scotia to implement an output-based pricing system ("OBPS") to comply with the Government of Canada's 2023 through 2030 carbon pollution pricing regulations effective January 1, 2023. The Government of Canada approved the Province's proposed system, however the OBPS will be subject to an interim review by the Government of Canada of the standards effective for 2026. The final Output-Based Pricing System Reporting and Compliance Regulations were prescribed by Order in Council dated January 30, 2024. The OBPS implements greenhouse gas ("GHG") emissions performance standards for large industrial GHG emitters that vary by fuel type. GHG emissions in excess of the prescribed intensity standards will be subject to a carbon price that starts at $65 per tonne in 2023 and will increase by $15 per tonne annually, reaching $170 per tonne by 2030. NSPI's regulatory framework provides for the recovery of costs prudently incurred to comply with carbon pricing programs pursuant to NSPI's FAM.

***Nova Scotia Cap-and-Trade Program Regulations:***

NSPI was a participant in the Nova Scotia Cap-and-Trade Program and was subject to the 2019 through 2022 compliance period. On March 16, 2023, the Province provided NSPI with emissions allowances sufficient to achieve compliance for the 2019 through 2022 compliance period. As such, compliance costs accrued of $166 million were reversed in Q1 2023. The credits NSPI purchased from provincial auctions in the amount of $6 million were not refunded and no further costs were incurred to achieve compliance with the Nova Scotia Cap-and-Trade Program.

### Other Legislation

***Electricity Act Amendment:***

On November 9, 2023, the Province enacted amendments in the Electricity Act which permit the Governor in Council to approve energy storage projects proposed by a public utility and owned wholly or in majority by the public utility if the project is in the best interest of ratepayers. Further, the amendments to the Electricity Act expand the ability of the Province to require NSPI to enter into power purchase agreements with renewable generation facilities by further empowering the Province to require NSPI to enter into an agreement for the sale of the electricity to specified customers. This allows specified customers to buy renewable electricity from specified producers, with NSPI managing the transmission and sale of the energy. On December 21, 2023, the Governor in Council enacted regulations which directed NSPI to install three 50 MW four-hour duration grid-scale batteries as part of the regulated assets of NSPI.

***Performance Standards Penalty Amendment:***

On April 12, 2023, the Province enacted amendments to the Public Utilities Act which increased the cumulative total of administrative penalties that could be levied by the UARB against NSPI for non-compliance with current and future performance standards in a calendar year from $1 million to $25 million. Any administrative penalties levied against NSPI must be credited to customers and NSPI cannot recover administrative penalties imposed through rates.

## ENL

Total equity earnings from NSPML and LIL are expected to be higher in 2024, compared to 2023 resulting from an increased investment in LIL planned for 2024. Both the NSPML and LIL investments are recorded as "Investments subject to significant influence" on Emera's Consolidated Balance Sheets.

### NSPML

Equity earnings from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. NSPML's approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 30 per cent.

The Maritime Link assets entered service on January 15, 2018, enabling the transmission of energy between Newfoundland and Nova Scotia, improved reliability and ancillary benefits, supporting the efficiency and reliability of energy in both provinces. Nalcor's NS Block delivery obligations commenced on August 15, 2021, and the NS Block will be delivered over the next 35 years pursuant to the project agreements.

On December 21, 2023, NSPML received approval to collect up to $164 million from NSPI for the recovery of costs associated with the Maritime Link in 2024; subject to a holdback of $4 million per month, as discussed below.

On October 4, 2023 and January 31, 2024, the UARB issued decisions providing clarification on remaining aspects of the Maritime Link holdback mechanism primarily relating to release of past and future holdback amounts and requirements to end the holdback mechanism. In these decisions, the UARB agreed with the Company's submission that $12 million ($8 million related to 2022 and $4 million relating to 2023) of the previously recorded holdback remain credited to NSPI's FAM, with the remainder released to NSPML and recorded in Emera's "Income from equity investments. NSPML did not record any additional holdback in Q4 2023. The UARB also confirmed that the holdback mechanism will cease once 90 per cent of NS Block deliveries are achieved for 12 consecutive months (subject to potential relief for planned outages or exceptional circumstances) and the net outstanding balance of previously underdelivered NS Block energy is less than 10 per cent of the contracted annual amount. In addition, the UARB increased the monthly holdback amount from $2 million to $4 million beginning December 1, 2023. NSPML expects to file an application to terminate the holdback mechanism in 2024.

NSPML does not anticipate any significant capital investment in 2024.

### LIL

ENL is a limited partner with Nalcor in LIL. Construction of the LIL is complete and the Newfoundland Electrical System Operator confirmed the asset to be operating suitably to support reliable system operation and full functionality at 700MW, which was validated by the Government of Canada's Independent Engineer issuing its Commissioning Certificate on April 13, 2023.

Upon issuance of the Commissioning Certificate, AFUDC equity earnings ceased and cash equity earnings and return of equity to Emera commenced. The first distribution was received from the LIL partnership in Q4 2023.

Equity earnings from the LIL investment are based upon the book value of the equity investment and the approved ROE. Emera's current equity investment is $747 million, comprised of $410 million in equity contribution and $337 million of accumulated equity earnings. Emera's total equity contribution in the LIL, excluding accumulated equity earnings, is estimated to be approximately $650 million once the final costing has been confirmed by Nalcor to determine the amount of the remaining investment.

## GAS UTILITIES AND INFRASTRUCTURE

Gas Utilities and Infrastructure includes PGS, NMGC, SeaCoast, Brunswick Pipeline and Emera's equity investment in M&NP. PGS is a regulated gas distribution utility engaged in the purchase, distribution and sale of natural gas serving customers in Florida. NMGC is an intrastate regulated gas distribution utility engaged in the purchase, transmission, distribution and sale of natural gas serving customers in New Mexico. SeaCoast is a regulated intrastate natural gas transmission company offering services in Florida. Brunswick Pipeline is a regulated 145-kilometre pipeline delivering re-gasified liquefied natural gas from Saint John, New Brunswick, to markets in the northeastern United States.

### Peoples Gas System

With $2.8 billion USD of assets and approximately 490,000 customers, the PGS system includes 24,300 kilometres of natural gas mains and 13,500 kilometres of service lines. Natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) was 2 billion therms in 2023.

Beginning in 2024, the approved ROE range for PGS is 9.15 per cent to 11.15 per cent (2023 – 8.9 per cent to 11.0 per cent), based on an allowed equity capital structure of 54.7 per cent (2023 – 54.7 per cent). An ROE of 10.15 per cent (2023 – 9.9 per cent) is used for the calculation of return on investments for clauses.

### New Mexico Gas Company, Inc.

With $1.8 billion USD of assets and approximately 540,000 customers, NMGC's system includes approximately 2,408 kilometres of transmission pipelines and 17,657 kilometres of distribution pipelines. Annual natural gas throughput was approximately 1 billion therms in 2023.

The approved ROE for NMGC is 9.375 per cent, on an allowed equity capital structure of 52 per cent.

### Gas Utilities and Infrastructure Outlook

Gas Utilities and Infrastructure USD earnings are anticipated to be higher in 2024 than 2023, primarily due to a base rate increase effective January 2024 at PGS and an expected base rate increase effective Q4 2024 at NMGC, partially offset by lower asset optimization revenues expected at NMGC.

PGS expects rate base to be higher than in 2023 and anticipates earning within its allowed ROE range in 2024. USD earnings for 2024 are expected to be to be significantly higher than in 2023 primarily due to higher revenue from new base rates in support of significant ongoing system investment and continued customer growth in 2024, which is expected to be consistent with Florida's population growth rates.

On April 4, 2023, PGS filed a rate case with the FPSC and a hearing for the matter was held in September 2023. On November 9, 2023, the FPSC approved a $118 million USD increase to base revenues which includes $11 million USD transferred from the cast iron and bare steel replacement rider, for a net incremental increase to base revenues of $107 million USD. This reflects a 10.15 per cent midpoint ROE with an allowed equity capital structure of 54.7 per cent. A final order was issued on December 27, 2023, with the new rates effective January 2024.

The 2020 PGS rate case settlement provided the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS reversed $20 million USD of accumulated depreciation in 2023 and $14 million USD in 2022.

NMGC expects 2024 rate base growth to be consistent with 2023, with slightly lower USD earnings as a result of lower asset optimization revenues, partially offset by higher revenue from expected new base rates, effective Q4 2024. NMGC anticipates earning near its authorized ROE in 2024. Customer growth rates are expected to be consistent with historical trends.

On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates to become effective Q4 2024. NMGC requested a $49 million USD increase in annual base revenues primarily as a result of increased operating costs and capital investments in pipeline projects and related infrastructure. The rate case includes a requested ROE of 10.5 per cent. A final order from the NMPRC is expected in Q3 2024.

In 2024, capital investment in the Gas Utilities and Infrastructure segment is expected to be approximately $465 million USD (2023 – $495 million USD), including AFUDC. PGS and NMGC will make investments to maintain the reliability of their systems and support customer growth.

## OTHER ELECTRIC UTILITIES

Other Electric Utilities includes Emera (Caribbean) Incorporated ("ECI"), a holding company with regulated electric utilities. ECI's regulated utilities include vertically integrated regulated electric utilities of BLPC on the island of Barbados, GBPC on Grand Bahama Island, and an equity investment in Lucelec on the island of St. Lucia.

### BLPC

With $517 million USD of assets and approximately 134,000 customers, BLPC owns 243 MW of generating capacity, of which 96 per cent is oil-fired and four per cent is solar. BLPC owns approximately 188 kilometres of transmission facilities and 3,839 kilometres of distribution facilities. BLPC's approved regulated return on rate base for 2023 was 10 per cent.

### GBPC

With $334 million USD of assets and approximately 19,000 customers, GBPC owns 98 MW of oil-fired generation, approximately 90 kilometres of transmission facilities and 994 kilometres of distribution facilities. GBPC's approved regulatory return on rate base for 2024 is 8.52 per cent (2023 – 8.32 per cent).

### Other Electric Utilities Outlook

Other Electric Utilities' USD earnings in 2024 are expected to increase over the prior year.

BLPC currently operates pursuant to a single integrated license to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation requiring multiple licenses for the supply of electricity. In 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The timing of the final enactment is unknown at this time, but BLPC will work towards the implementation of the licenses once enacted.

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 related to the self-insurance fund of $50 million USD, prior year benefits recognized on remeasurement of deferred income taxes of $5 million USD, and accumulated depreciation of $16 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. Management does not expect the final decision and order to have a material impact on adjusted net income.

In 2024, capital investment in the Other Electric Utilities segment is expected to be approximately $80 million USD (2023 – $47 million USD), primarily in more efficient and cleaner sources of generation, including renewables and battery storage.

## OTHER

The Other segment includes those business operations that in a normal year 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.

Business operations in the Other segment include Emera Energy and Block Energy LLC ("Block Energy"). Emera Energy consists of EES, a wholly owned physical energy marketing and trading business and an equity investment in a 50 per cent joint venture ownership of Bear Swamp, a 660 MW pumped storage hydroelectric facility in northwestern Massachusetts. Block Energy is a wholly owned technology company focused on finding ways to deliver renewable and resilient energy to customers.

Corporate items included in the Other segment are certain corporate-wide functions including executive management, strategic planning, treasury services, legal, financial reporting, tax planning, corporate business development, corporate governance, investor relations, risk management, insurance, acquisition and disposition related costs, gains or losses on select assets sales, and corporate human resource activities. It includes interest revenue on intercompany financings and interest expense on corporate debt in both Canada and the United States. It also includes costs associated with corporate activities that are not directly allocated to the operations of Emera's subsidiaries and investments.

Earnings from EES are generally dependent on market conditions. In particular, volatility in natural gas and electricity markets, which can be influenced by weather, local supply constraints and other supply and demand factors, can provide higher levels of margin opportunity. The business is seasonal, with Q1 and Q4 usually providing the greatest opportunity for earnings. EES is generally expected to deliver annual adjusted net income within its guidance range of $15 to $30 million USD.

The adjusted net loss from the Other segment is expected to be higher in 2024 due to increased interest expense and lower contribution to net income from Emera Energy primarily as a result of one-time investment tax credits at Bear Swamp in 2023.

The Other segment does not anticipate any significant capital investment in 2024.

## Consolidated Balance Sheet Highlights

Significant changes in the Consolidated Balance Sheets between December 31, 2022 and December 31, 2023 include:

| millions of dollars | Increase (Decrease) | Explanation |
|---|---|---|
| **Assets** | | |
| Cash and cash equivalents | **$ 257** | Increased due to cash from operations, proceeds from long-term debt issuances at PGS and NSPI, and issuance of Emera common stock. These were partially offset by investment in PP&E at the regulated utilities, net repayments of debt at TEC, and dividends paid on Emera common stock |
| Derivative instruments (current and long-term) | **(156)** | Decreased due to settlements of derivative instruments and decreased pricing on power derivative instruments at NSPI, partially offset by reversal of 2022 contracts at EES |
| Regulatory assets (current and long-term) | **(515)** | Decreased due to higher fuel clause and storm cost recoveries at TEC, and reversal of accrued Cap-and-Trade emission compliance charges at NSPI. These were partially offset by increased FAM deferrals at NSPI due to an under-recovery of fuel costs and a change in fuel cost recovery methodology for an industrial customer, and increased deferred income tax regulatory assets at NSPI |
| Receivables and other assets (current and long-term) | **(1,079)** | Decreased due to lower gas transportation assets, decreased cash collateral and lower trade receivables as a result of lower commodity prices at EES, and settlement of the gas hedge receivable at NMGC |
| PP&E, net of accumulated depreciation and amortization | **1,380** | Increased due to capital additions in excess of depreciation and amortization, partially offset by the effect of FX translation of Emera's non-Canadian affiliates |
| Goodwill | **(141)** | Decreased due to the effect of the FX translation of non-Canadian affiliates |
| **Liabilities and Equity** | | |
| Short-term debt and long-term debt (including current portion) | **$ 754** | Issuance of long-term debt at PGS and NSPI and proceeds from committed credit facilities at Emera, partially offset by net repayments under committed credit facilities at NSPI and TEC, repayment of debt at NMGC, and the effect of the FX translation of non-Canadian affiliates |
| Accounts payable | **(571)** | Decreased due to lower commodity prices at EES, NMGC and TEC, decreased cash collateral position on derivative instruments and lower fuel related payables at NSPI |
| Deferred income tax liabilities, net of deferred income tax assets | **185** | Increased due to tax deductions in excess of accounting depreciation related to PP&E, partially offset by changes in derivative instruments and increased tax credits related to solar projects at TEC and Bear Swamp facility upgrades |
| Derivative instruments (current and long-term) | **(574)** | Decreased due to changes in existing positions and reversal of 2022 contracts, partially offset by new contracts in 2023 at EES |
| Regulatory liabilities (current and long-term) | **(501)** | Decreased due to lower deferrals related to derivative instruments at NSPI and settlement of NMGC gas hedges |
| Other liabilities (current and long-term) | **(157)** | Decreased due to reversal of accrued Cap-and-Trade emissions compliance charges at NSPI |
| Common stock | **700** | Increased due to shares issued |
| Accumulated other comprehensive income | **(273)** | Decreased due to the effect of the FX translation of non-Canadian affiliates |
| Retained earnings | **219** | Increased due to net income in excess of dividends paid |

# Other Developments

### Increase in Common Dividends

On September 20, 2023, the Emera Board of Directors (the "Board") approved an increase in the annual common share dividend rate to $2.87 from $2.76 per common share. The first payment was effective November 15, 2023. Emera also extended its dividend growth rate target of four to five per cent through 2026.

# Financial Highlights

## FLORIDA ELECTRIC UTILITY

| For the<br>millions of USD (except as indicated) | Three months ended December 31<br>**2023** | <br>2022 | Year ended December 31<br>**2023** | <br>2022 |
|---|---|---|---|---|
| Operating revenues – regulated electric | **$ 613** | $ 597 | **$ 2,637** | $ 2,523 |
| Regulated fuel for generation and purchased power | **$ 162** | $ 201 | **$ 682** | $ 832 |
| Contribution to consolidated net income | **$ 85** | $ 91 | **$ 466** | $ 458 |
| Contribution to consolidated net income – CAD | **$ 115** | $ 124 | **$ 627** | $ 596 |
| Average fuel costs in dollars per MWh | **$ 34** | $ 41 | **$ 31** | $ 39 |

The impact of the change in the FX rate increased CAD earnings for the three months and year ended December 31, 2023, by $1 million and $22 million, respectively.

### Net Income

Highlights of the net income changes are summarized in the following table:

| For the<br>millions of USD | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2022** | **$ 91** | **$ 458** |
| Increased operating revenues due to storm cost recovery surcharge revenue (offset in OM&G), new base rates and customer growth driving higher sales volumes, partially offset by changes in fuel recovery clause revenue and unfavourable weather | 16 | 114 |
| Decreased fuel for generation and purchased power due to lower natural gas prices | 39 | 150 |
| Increased OM&G primarily due to storm cost recovery recognition related to the storm surcharge (offset in revenue) and timing of deferred clause recoveries | (25) | (136) |
| Increased depreciation and amortization due to additions to facilities and generation projects placed in service | (8) | (33) |
| Increased interest expense due to higher interest rates and higher borrowings to support capital investments and ongoing operations | (7) | (59) |
| Increased state, and municipal taxes due to higher retail sales and higher taxable property placed in service | (8) | (33) |
| (Increased) decreased income tax expense primarily due to production tax credits related to solar facilities | (6) | 7 |
| Other | (7) | (2) |
| **Contribution to consolidated net income – 2023** | **$ 85** | **$ 466** |

### Operating Revenues – Regulated Electric

Annual electric revenues and sales volumes are summarized in the following table by customer class:

| | Electric Revenues (millions of USD) | | Electric Sales Volumes (Gigawatt hours ("GWh")) | |
|---|---|---|---|---|
| | **2023** | 2022 | **2023** | 2022 |
| Residential | **$ 1,711** | $ 1,381 | **10,307** | 10,109 |
| Commercial | **803** | 666 | **6,462** | 6,300 |
| Industrial | **203** | 176 | **2,082** | 2,111 |
| Other (1) | **(80)** | 300 | **2,194** | 2,352 |
| Total | **$ 2,637** | $ 2,523 | **21,045** | 20,872 |

(1) Other includes regulatory deferrals related to clauses, sales to public authorities, off-system sales to other utilities.

### Regulated Fuel for Generation and Purchased Power

Annual production volumes are summarized in the following table:

| | Production Volumes (GWh) | |
|---|---|---|
| | **2023** | 2022 |
| Natural gas | **17,843** | 17,083 |
| Solar | **1,748** | 1,492 |
| Purchased power | **1,443** | 1,685 |
| Coal | **744** | 1,325 |
| Total | **21,778** | 21,585 |

TEC's fuel costs are affected by commodity prices and generation mix that is largely dependent on economic dispatch of the generating fleet, bringing the lowest cost options on first (renewable energy from solar or battery storage), such that the incremental cost of production increases as sales volumes increase. Generation mix may also be affected by plant outages, plant performance, availability of lower priced short-term purchased power, availability of renewable solar generation, and compliance with environmental standards and regulations.

### Regulatory Environment

TEC is regulated by the FPSC and is also subject to regulation by the FERC. The FPSC sets rates at a level that allows utilities such as TEC to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital. Base rates are determined in FPSC rate setting hearings which can occur at the initiative of TEC, the FPSC or other interested parties. For further details on TEC's regulatory environment, base rates and recovery mechanisms, refer to note 6 in the consolidated financial statements.

## CANADIAN ELECTRIC UTILITIES

| For the<br>millions of dollars (except as indicated) | Three months ended December 31 **2023** | 2022 | Year ended December 31 **2023** | 2022 |
|---|---|---|---|---|
| Operating revenues – regulated electric | **$ 439** | $ 421 | **$ 1,671** | $ 1,675 |
| Regulated fuel for generation and purchased power (1) | **$ 234** | $ 173 | **$ 777** | $ 950 |
| Contribution to consolidated adjusted net income | **$ 68** | $ 46 | **$ 247** | $ 222 |
| NSPML unrecoverable costs | **$ –** | $ – | **$ –** | $ (7) |
| Contribution to consolidated net income | **$ 68** | $ 46 | **$ 247** | $ 215 |
| Average fuel costs in dollars per MWh (2) | **$ 81** | $ 61 | **$ 70** | $ 85 |

(1) Regulated fuel for generation and purchased power includes NSPI's FAM deferral on the Consolidated Statements of Income, however, it is excluded in the segment overview.
(2) Average fuel costs for the year ended December 31, 2023 include reversal of the $166 million of the Nova Scotia Cap-and-Trade Program provision (2022 – $134 million expense).

Canadian Electric Utilities' contribution to consolidated adjusted net income is summarized in the following table:

| For the<br>millions of dollars | Three months ended<br>December 31<br>**2023** | <br><br>2022 | Year ended<br>December 31<br>**2023** | <br><br>2022 |
|---|---|---|---|---|
| NSPI | **$ 40** | $ 23 | **$ 141** | $ 131 |
| Equity investment in LIL | **16** | 15 | **60** | 55 |
| Equity investment in NSPML (1) | **12** | 8 | **46** | 36 |
| **Contribution to consolidated adjusted net income** | **$ 68** | $ 46 | **$ 247** | $ 222 |

(1) Excludes $7 million in NSPML unrecoverable costs, after-tax, for the year ended December 31, 2022.

## Net Income

Highlights of the net income changes are summarized in the following table:

| For the<br>millions of dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2022** | **$ 46** | **$ 215** |
| Increased operating revenues quarter-over-quarter due to new rates, increased residential, commercial and other class sales volumes, and favourable weather, partially offset by decreased industrial sales volume. Year-over-year decrease primarily due to changes in fuel cost recovery methodology for an industrial customer (1), partially offset by quarter-over-quarter impacts noted above | 18 | (4) |
| Increased fuel for generation and purchased power quarter-over-quarter due to increased commodity prices and partial reversal of Nova Scotia Cap-and-Trade Program costs accrued in 2022, partially offset by a change in generation mix. Year-over-year decreased due to reversal of the Nova Scotia Cap-and-Trade Program provision in 2023, compared to an expense in 2022, partially offset by increased commodity prices and the Nova Scotia OBPS carbon tax accrual | (61) | 173 |
| Increased FAM deferral quarter-over-quarter due to under-recovery of fuel costs. Year-over-year decreased due to reversal of the Nova Scotia Cap-and-Trade provision in 2023, partially offset by increased under-recovery of fuel costs and changes in the fuel recovery methodology for an industrial customer (1) | 74 | (69) |
| Increased OM&G due to higher costs for power generation and transmission and distribution field services. Year-over-year also increased due to the recognition of the RER penalty and higher vegetation management costs | (8) | (46) |
| Increased depreciation and amortization due to increased PP&E in service | (3) | (17) |
| Increased interest expense due to increased interest rates and higher debt levels | (5) | (34) |
| Increased income from equity investments at NSPML quarter-over-quarter primarily due to the holdback recognized in Q4 2022. Year-over-year also increased due to partial reversal in Q3 2023 of the holdback recognized in 2022, and higher equity earnings from LIL | 5 | 15 |
| NSPML unrecoverable costs in 2022 | – | 7 |
| Other | 2 | 7 |
| **Contribution to consolidated net income – 2023** | **$ 68** | **$ 247** |

(1) For more information on the changes in fuel cost recovery methodology for an industrial customer, refer to note 6 in the 2023 consolidated financial statements

## NSPI

### Operating Revenues – Regulated Electric

Annual electric revenues and sales volumes are summarized in the following tables by customer class:

| | Electric Revenues (millions of dollars) | | Electric Sales Volumes (GWh) | |
|---|---|---|---|---|
| | **2023** | 2022 | **2023** | 2022 |
| Residential | **$ 910** | $ 834 | **4,986** | 4,822 |
| Commercial | **463** | 427 | **3,053** | 3,006 |
| Industrial | **219** | 353 | **2,164** | 2,480 |
| Other | **41** | 28 | **239** | 148 |
| Total | **$ 1,633** | $ 1,642 | **10,442** | 10,456 |

### Regulated Fuel for Generation and Purchased Power

Annual production volumes are summarized in the following table:

| | Production Volumes (GWh) | |
|---|---|---|
| | **2023** | 2022 |
| Coal | **3,086** | 3,771 |
| Natural gas | **1,946** | 1,650 |
| Purchased power | **881** | 910 |
| Petcoke | **553** | 897 |
| Oil | **145** | 251 |
| Total non-renewables | **6,611** | 7,479 |
| Purchased power – IPP, COMFIT and imports | **3,251** | 2,423 |
| Wind, hydro and solar | **1,149** | 1,105 |
| Biomass | **128** | 127 |
| Total renewables | **4,528** | 3,655 |
| Total production volumes | **11,139** | 11,134 |

NSPI's fuel costs are affected by commodity prices and generation mix, which is largely dependent on economic dispatch of the generating fleet. NSPI brings the lowest cost options on stream first after renewable energy from IPPs including COMFIT participants, for which NSPI has power purchase agreements in place, and the NS Block of energy, including the Supplemental Energy Block, which carries no additional fuel cost outside of the UARB approved annual assessments paid to NSPML for the use of the Maritime Link.

Generation mix may also be affected by plant outages, carbon pricing programs, including the Nova Scotia OBPS, availability of renewable generation, availability of energy from the NS Block, plant performance, and compliance with environmental regulations.

The Nova Scotia Cap-and-Trade Program provision related to the accrued cost of acquiring emissions credits for the 2019 through 2022 compliance period. As of December 31, 2022, NSPI had recognized a cumulative $166 million accrual in fuel costs related to anticipated purchase of emissions credits and $6 million related to credits purchased from provincial auction. Accrued compliance costs of $166 million were reversed in Q1 2023 and NSPI does not anticipate further costs related to the Nova Scotia Cap-and-Trade Program. For further information on the reversal of this non-cash accrual and the FAM regulatory balance, refer to the "Business Overview and Outlook – Canadian Electric Utilities – NSPI" section and note 6 in the consolidated financial statements.

## Regulatory Environment – NSPI

NSPI is a public utility as defined in the Public Utilities Act and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings held from time to time at NSPI's or the UARB's request. For further details on NSPI's regulatory environment and recovery mechanisms, refer to note 6 in the consolidated financial statements.

## GAS UTILITIES AND INFRASTRUCTURE

| For the millions of USD (except as indicated) | Three months ended December 31 2023 | 2022 | Year ended December 31 2023 | 2022 |
|---|---|---|---|---|
| Operating revenues – regulated gas (1) | **$ 290** | $ 372 | **$ 1,114** | $ 1,296 |
| Operating revenues – non-regulated | **3** | 2 | **15** | 12 |
| Total operating revenue | **$ 293** | $ 374 | **$ 1,129** | $ 1,308 |
| Regulated cost of natural gas | **$ 99** | $ 181 | **$ 391** | $ 614 |
| Contribution to consolidated net income | **$ 43** | $ 53 | **$ 158** | $ 170 |
| Contribution to consolidated net income – CAD | **$ 59** | $ 72 | **$ 214** | $ 221 |

(1) Operating revenues – regulated gas includes $11 million of finance income from Brunswick Pipeline (2022 – $13 million) for the three months ended December 31, 2023 and $46 million (2022 – $47 million) for the year ended December 31 2023; however, it is excluded from the gas revenues and cost of natural gas analysis below.

Gas Utilities and Infrastructure's contribution to consolidated net income is summarized in the following table:

| For the millions of USD | Three months ended December 31 2023 | 2022 | Year ended December 31 2023 | 2022 |
|---|---|---|---|---|
| PGS | **$ 21** | $ 17 | **$ 79** | $ 82 |
| NMGC | **14** | 22 | **43** | 35 |
| Other | **8** | 14 | **36** | 53 |
| **Contribution to consolidated net income** | **$ 43** | $ 53 | **$ 158** | $ 170 |

Impact of the change in the FX rate on CAD earnings was minimal for the three months ended and increased CAD earnings for the year ended December 31, 2023, by $8 million.

### Net Income

Highlights of the net income changes are summarized in the following table:

| For the millions of USD | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2022** | **$ 53** | **$ 170** |
| Decreased operating revenues due to lower fuel revenues at PGS and NMGC, and lower off-system sales at PGS, partially offset by new base rates at NMGC and customer growth at PGS | (71) | (181) |
| Decreased asset optimization revenue quarter-over-quarter at NMGC | (10) | 2 |
| Decreased cost of natural gas sold due to lower natural gas prices at PGS and NMGC | 82 | 223 |
| Increased OM&G primarily due to higher labour and benefit costs | (10) | (20) |
| Decreased depreciation and amortization expense quarter-over-quarter due to a higher reversal of accumulated depreciation in 2023 as a result of the 2021 rate case settlement at PGS. Year-over-year increase due to asset growth at PGS and NMGC, partially offset by a higher reversal of accumulated depreciation in 2023 at PGS | 6 | (3) |
| Increased interest expense due to higher interest rates and increased borrowings to support ongoing operations and capital investments | (10) | (33) |
| Other | 3 | – |
| **Contribution to consolidated net income – 2023** | **$ 43** | **$ 158** |

## Operating Revenues – Regulated Gas

Annual gas revenues and sales volumes are summarized in the following tables by customer class:

| | Gas Revenues (millions of USD) | | Gas Volumes (Therms) | |
|---|---|---|---|---|
| | **2023** | 2022 | **2023** | 2022 |
| Residential | **$ 537** | $ 614 | **414** | 421 |
| Commercial | **315** | 354 | **839** | 836 |
| Industrial (1) | **69** | 64 | **1,615** | 1,429 |
| Other (2) | **147** | 217 | **266** | 227 |
| Total (3) | **$ 1,068** | $ 1,249 | **3,134** | 2,913 |

(1) Industrial gas revenue includes sales to power generation customers.
(2) Other gas revenue includes off-system sales to other utilities and various other items.
(3) Total gas revenue excludes $46 million of finance income from Brunswick Pipeline (2022 – $47 million).

## Regulated Cost of Natural Gas

PGS and NMGC purchase gas from various suppliers depending on the needs of their customers. In Florida, gas is delivered to the PGS distribution system through interstate pipelines on which PGS has firm transportation capacity for delivery by PGS to its customers. NMGC's natural gas is transported on major interstate pipelines and NMGC's intrastate transmission and distribution system for delivery to customers.

In Florida, natural gas service is unbundled for non-residential customers and residential customers who use more than 1,999 therms annually and elect the option. In New Mexico, NMGC is required, if requested, to provide transportation-only services for all customer classes. The commodity portion of bundled sales is included in operating revenues, at the cost of the gas on a pass-through basis, therefore no net earnings effect when a customer shifts to transportation-only sales.

Annual gas sales by type are summarized in the following table:

| | Gas Volumes by Type (millions of Therms) | |
|---|---|---|
| | **2023** | 2022 |
| Transportation | **2,461** | 2,206 |
| System supply | **673** | 707 |
| Total | **3,134** | 2,913 |

## Regulatory Environments

PGS is regulated by the FPSC. The FPSC sets rates at a level that allows utilities such as PGS to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

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

For further information on PGS and NMGC's regulatory environment and recovery mechanisms, refer to note 6 in the consolidated financial statements.

## OTHER ELECTRIC UTILITIES

| For the<br>millions of USD (except as indicated) | Three months ended December 31 2023 | 2022 | Year ended December 31 2023 | 2022 |
|---|---|---|---|---|
| Operating revenues – regulated electric | **$ 104** | $ 98 | **$ 390** | $ 398 |
| Regulated fuel for generation and purchased power | **$ 57** | $ 54 | **$ 204** | $ 223 |
| Contribution to consolidated adjusted net income | **$ 3** | $ 7 | **$ 26** | $ 23 |
| Contribution to consolidated adjusted net income – CAD | **$ 4** | $ 8 | **$ 35** | $ 29 |
| GBPC Impairment charge | **$ –** | $ 54 | **$ –** | $ 54 |
| Equity securities MTM gain (loss) | **$ 2** | $ 1 | **$ 2** | $ (4) |
| Contribution to consolidated net income (loss) | **$ 5** | $ (46) | **$ 28** | $ (35) |
| Contribution to consolidated net income (loss) – CAD | **$ 6** | $ (62) | **$ 37** | $ (48) |
| Electric sales volumes (GWh) | **323** | 301 | **1,260** | 1,239 |
| Electric production volumes (GWh) | **345** | 325 | **1,362** | 1,340 |
| Average fuel cost in dollars per MWh | **$ 165** | $ 161 | **$ 150** | $ 166 |

On March 31, 2022, Emera completed the sale of its 51.9 per cent interest in Dominica Electricity Services Ltd. ("Domlec") for proceeds which approximated carrying value. The sale did not have a material impact on earnings.

The impact of the change in the FX rate on CAD earnings for the three months and year ended December 31, 2023 was minimal.

Other Electric Utilities' contribution to consolidated adjusted net income is summarized in the following table:

| For the<br>millions of USD | Three months ended December 31 2023 | 2022 | Year ended December 31 2023 | 2022 |
|---|---|---|---|---|
| BLPC | **$ 4** | $ 5 | **$ 18** | $ 11 |
| GBPC | **–** | 1 | **11** | 10 |
| Other | **(1)** | 1 | **(3)** | 2 |
| **Contribution to consolidated adjusted net income** | **$ 3** | $ 7 | **$ 26** | $ 23 |

### Net Income

Highlights of the net income changes are summarized in the following table:

| For the<br>millions of USD | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Contribution to consolidated net income – 2022** | **$ (46)** | **$ (35)** |
| Increased operating revenues quarter-over-quarter due to higher fuel revenue at BLPC and GBPC as a result of higher fuel prices and higher sales volumes at BLPC. Year-over-year decreased due to lower fuel revenue at BLPC reflecting lower fuel prices, and the sale of Domlec in Q1 2022, partially offset by interim rates at BLPC and increased sales volumes at BLPC and GBPC | 6 | (8) |
| Increased fuel for generation and purchased power quarter-over-quarter due to higher fuel costs at BLPC and GBPC. Decreased year-over-year due to lower fuel prices and change in generation mix at BLPC | (3) | 19 |
| GBPC impairment charge in 2022 | 54 | 54 |
| Other | (6) | (2) |
| **Contribution to consolidated net income – 2023** | **$ 5** | **$ 28** |

### Regulatory Environments

BLPC is regulated by the FTC. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested.

GBPC is regulated by the GBPA. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base.

For further details on BLPC and GBPC's regulatory environments and recovery mechanisms, refer to note 6 in the consolidated financial statements.

## OTHER

| For the millions of dollars | Three months ended December 31 2023 | 2022 | Year ended December 31 2023 | 2022 |
|---|---|---|---|---|
| Marketing and trading margin (1) (2) | **$ 35** | $ 72 | **$ 96** | $ 143 |
| Other non-regulated operating revenue | **5** | 3 | **27** | 16 |
| Total operating revenues – non-regulated | **$ 40** | $ 75 | **$ 123** | $ 159 |
| Contribution to consolidated adjusted net income (loss) | **$ (71)** | $ (1) | **$ (314)** | $ (218) |
| MTM gain, after-tax (3) | **112** | 304 | **167** | 179 |
| Contribution to consolidated net income (loss) | **$ 41** | $ 303 | **$ (147)** | $ (39) |

(1) Marketing and trading margin represents EES's purchases and sales of natural gas and electricity, pipeline and storage capacity costs and energy asset management services' revenues.
(2) Marketing and trading margin excludes a MTM gain, pre-tax of $131 million in Q4 2023 (2022 – $430 million gain) and a gain of $216 million for the year ended December 31, 2023 (2022 – $281 million gain).
(3) Net of income tax expense of $44 million for the three months ended December 31, 2023 (2022 – $124 million expense) and $68 million expense for the year ended December 31, 2023 (2022 – $73 million expense).

Other's contribution to consolidated adjusted net income is summarized in the following table:

| For the millions of dollars | Three months ended December 31 2023 | 2022 | Year ended December 31 2023 | 2022 |
|---|---|---|---|---|
| Emera Energy | | | | |
| EES | **$ 19** | $ 40 | **$ 46** | $ 68 |
| Other | **6** | 1 | **18** | 2 |
| Corporate – see breakdown of adjusted contribution below | **(91)** | (37) | **(356)** | (267) |
| Block Energy LLC (1) | **(4)** | (5) | **(18)** | (18) |
| Other | **(1)** | – | **(4)** | (3) |
| **Contribution to consolidated adjusted net income (loss)** | **$ (71)** | $ (1) | **$ (314)** | $ (218) |

(1) Previously Emera Technologies LLC

## Net Income

Highlights of the net income changes are summarized in the following table:

| For the<br>millions of dollars | Three months ended<br>December 31 | Year ended<br>December 31 |
|---|---|---|
| **Contribution to consolidated net income (loss) – 2022** | **$ 303** | **$ (39)** |
| Decreased marketing and trading margin quarter-over-quarter primarily due to weather driven market conditions in Q4 2022 that increased pricing and volatility. Year-over-year decrease reflects less favourable market conditions, specifically lower natural gas prices and volatility and higher cost commitments for gas transportation in 2023 compared to 2022 | (37) | (47) |
| Decreased OM&G, pre-tax, primarily due to the timing of long-term compensation and related hedges | 12 | 10 |
| Increased interest expense, pre-tax, due to increased interest rates and increased total debt | (8) | (51) |
| Increased income tax recovery primarily due to increased losses before provision for income taxes and the recognition of investment tax credits related to Bear Swamp facility upgrades, partially offset by the impact of effective state tax rates | 7 | 26 |
| TGH award in 2022, after tax and legal costs | (45) | (45) |
| Decreased MTM gain, after-tax, quarter-over-quarter due to unfavourable changes in existing positions, partially offset by higher amortization of gas transportation assets in 2022 at EES. Decreased MTM gain after-tax, year-over-year primarily due to higher amortization of gas transportation assets partially offset by favourable changes in existing positions at EES and gains on Corporate FX hedges | (194) | (12) |
| Other | 3 | 11 |
| **Contribution to consolidated net income (loss) – 2023** | **$ 41** | **$ (147)** |

## Emera Energy

EES derives revenue and earnings from wholesale marketing and trading of natural gas and electricity within the Company's risk tolerances, including those related to value-at-risk ("VaR") and credit exposure. EES purchases and sells physical natural gas and electricity, the related transportation and transmission capacity rights, and provides energy asset management services. The primary market area for the natural gas and power marketing and trading business is northeastern North America, including the Marcellus and Utica shale supply areas. EES also participates in the Florida, United States Gulf Coast and Midwest/Central Canadian natural gas markets. Its counterparties include electric and gas utilities, natural gas producers, electricity generators and other marketing and trading entities. EES operates in a competitive environment, and the business relies on knowledge of the region's energy markets, understanding of pipeline and transmission infrastructure, a network of counterparty relationships and a focus on customer service. EES manages its commodity risk by limiting open positions, utilizing financial products to hedge purchases and sales, and investing in transportation capacity rights to enable movement across its portfolio.

EES' contribution to consolidated adjusted net income was $19 million in Q4 2023, compared to $40 million in Q4 2022; and $46 million ($33 million USD) for the year ended December 31, 2023, compared to $68 million ($50 million USD) for the same period in 2022. The 2023 and 2022 EES contribution to consolidated adjusted net income was above the expected EES annual adjusted net income guidance range of $15 to $30 million USD. Market conditions in 2022 were very favourable, due to high natural gas pricing and volatility, which reflected weather patterns and geopolitical conditions.

## MTM Adjustments

Emera Energy's "Marketing and trading margin", "Non-regulated fuel for generation and purchased power", "Income from equity investments" and "Income tax expense (recovery)" are affected by MTM adjustments. Management believes excluding the effect of MTM valuations, and changes thereto, from income until settlement better matches the financial effect of these contracts with the underlying cash flows. Variance explanations of the MTM changes for this quarter and for the year are explained in the table below.

Emera Energy has a number of asset management agreements ("AMA") with counterparties, including local gas distribution utilities, power utilities and natural gas producers in North America. The AMAs involve Emera Energy buying or selling gas for a specific term, and the corresponding release of the counterparties' gas transportation/storage capacity to Emera Energy. MTM adjustments on these AMAs arise on the price differential between the point where gas is sourced and where it is delivered. At inception, the MTM adjustment is offset fully by the value of the corresponding gas transportation asset, which is amortized over the term of the AMA contract.

Subsequent changes in gas price differentials, to the extent they are not offset by the accounting amortization of the gas transportation asset, will result in MTM gains or losses recorded in income. MTM adjustments may be substantial during the term of the contract, especially in the winter months of a contract when delivered volumes and market pricing are usually at peak levels. As a contract is realized, and volumes reduce, MTM volatility is expected to decrease. Ultimately, the gas transportation asset and the MTM adjustment reduce to zero at the end of the contract term. As the business grows, and AMA volumes increase, MTM volatility resulting in gains and losses may also increase.

Emera Corporate has FX forwards to manage the cash flow risk of forecasted USD cash inflows. Fluctuations in the FX rate result in MTM gains or losses are recorded in "Other income, net" on the Consolidated Statements of Income.

### Corporate

Corporate's adjusted loss is summarized in the following table:

| For the<br>millions of dollars | Three months ended December 31<br>**2023** | 2022 | Year ended December 31<br>**2023** | 2022 |
|---|---|---|---|---|
| Operating expenses (1) | **$ 7** | $ 20 | **$ 73** | $ 83 |
| Interest expense | **88** | 79 | **329** | 278 |
| Income tax recovery | **(25)** | (35) | **(111)** | (109) |
| Preferred dividends | **18** | 16 | **66** | 63 |
| TGH award, after tax and legal costs | **–** | (45) | **–** | (45) |
| Other (2) (3) | **3** | 2 | **(1)** | (3) |
| **Corporate adjusted net loss (4)** | **$ (91)** | $ (37) | **$ (356)** | $ (267) |

(1) Operating expenses include OM&G and depreciation.
(2) Other includes realized FX gains and losses on FX hedges entered into to hedge USD denominated operating unit earnings exposure.
(3) Includes a realized net loss, pre-tax of $4 million ($3 million after-tax) for the three months ended December 31, 2023 (2022 – $5 million net loss, pre-tax and $4 million loss, after-tax) and a $11 million net loss, pre-tax ($8 million after-tax) for the year ended December 31, 2023 (2022 – $6 million net loss, pre-tax and $5 million loss after-tax) on FX hedges, as discussed above.
(4) Excludes a MTM gain, after-tax of $15 million for the three months ended December 31, 2023 (2022 – $9 million gain, after-tax) and a MTM gain, after-tax of $20 million for the year ended December 31, 2023 (2022 – $12 million loss, after-tax).

## Liquidity and Capital Resources

The Company generates internally sourced cash from its various regulated and non-regulated energy investments. Utility customer bases are diversified by both sales volumes and revenues among customer classes. Emera's non-regulated businesses provide diverse revenue streams and counterparties to the business. Circumstances that could affect the Company's ability to generate cash include changes to global macro-economic conditions, downturns in markets served by Emera, impact of fuel commodity price changes on collateral requirements and timely recoveries of fuel costs from customers, the loss of one or more large customers, regulatory decisions affecting customer rates and the recovery of regulatory assets, and changes in environmental legislation. Emera's subsidiaries are generally in a financial position to contribute cash dividends to Emera provided they do not breach their debt covenants, where applicable, after giving effect to the dividend payment, and maintain their credit metrics.

Emera's future liquidity and capital needs will be predominately for working capital requirements, ongoing rate base investment, business acquisitions, greenfield development, dividends and debt servicing. Emera has an approximate $9 billion capital investment plan over the 2024 through 2026 period with approximately $2 billion of additional potential capital investments over the same period. Capital investments at Emera's regulated utilities are subject to regulatory approval.

Emera plans to use cash from operations, debt raised at the utilities, equity, and select asset sales to support normal operations, repayment of existing debt, and capital requirements. Debt raised at certain of the Company's utilities is subject to applicable regulatory approvals. Generally, equity requirements in support of the Company's capital investment plan are expected to be funded through issuance of preferred equity and issuance of common equity through Emera's DRIP and ATM programs.

Emera has credit facilities with varying maturities that cumulatively provide $5.3 billion of credit, with approximately $2.3 billion undrawn and available at December 31, 2023. The Company was holding a cash balance of $588 million at December 31, 2023. For further discussion, refer to the "Debt Management" section below. For additional information regarding the credit facilities, refer to notes 23 and 25 in the consolidated financial statements.

## CONSOLIDATED CASH FLOW HIGHLIGHTS

Significant changes in the Consolidated Statements of Cash Flows between the years ended December 31, 2023 and 2022 include:

| millions of dollars | 2023 | 2022 | $ Change |
|---|---|---|---|
| Cash, cash equivalents and restricted cash, beginning of period | **$ 332** | $ 417 | $ (85) |
| **Provided by (used in):** | | | |
| Operating cash flow before changes in working capital | **2,336** | 1,147 | 1,189 |
| Change in working capital | **(95)** | (234) | 139 |
| Operating activities | **$ 2,241** | $ 913 | $ 1,328 |
| Investing activities | **(2,917)** | (2,569) | (348) |
| Financing activities | **939** | 1,555 | (616) |
| Effect of exchange rate changes on cash, cash equivalents and restricted cash | **(7)** | 16 | (23) |
| Cash, cash equivalents, and restricted cash, end of period | **$ 588** | $ 332 | $ 256 |

### Cash Flow from Operating Activities

Net cash provided by operating activities increased $1,328 million to $2,241 million for the year ended December 31, 2023, compared to $913 million in 2022.

Cash from operations before changes in working capital increased $1,189 million for the year ended December 31, 2023. This increase was due to higher fuel clause recoveries and favourable changes in the storm reserve balance at TEC, decreased fuel for generation and purchased power expense at NSPI driven by the decreased Nova Scotia Cap-and-Trade Program provision and a distribution received from the LIL partnership. This was partially offset by a decrease in regulatory liabilities due to 2022 gas hedge settlements at NMGC, and receipt of the TGH award in 2022.

Changes in working capital increased operating cash flows by $139 million for the year ended December 31, 2023. This increase was due to favourable changes in accounts receivable at NMGC due to receipt of its 2022 gas hedge settlement, favourable changes in cash collateral positions at Emera Energy, favourable changes in natural gas inventory at EES in 2023, and the required prepayment of income taxes and related interest in 2022 at NSPI. These increases were offset by the timing of accounts payable payments at NSPI, TEC and NMGC, unfavourable changes in cash collateral positions at NSPI, and decreased accrual for the Nova Scotia Cap-and-Trade emissions compliance charges at NSPI.

### Cash Flow Used in Investing Activities

Net cash used in investing activities increased $348 million to $2,917 million for the year ended December 31, 2023, compared to $2,569 million in 2022. The increase was due to higher capital investment in 2023.

Capital expenditures for the year ended December 31, 2023, including AFUDC, were $2,976 million compared to $2,646 million in 2022. Details of 2023 capital spending by segment are shown below:

- $1,771 million – Florida Electric Utility (2022 – $1,481 million);
- $461 million – Canadian Electric Utilities (2022 – $518 million);
- $673 million – Gas Utilities and Infrastructure (2022 – $578 million);
- $63 million – Other Electric Utilities (2022 – $63 million); and
- $8 million – Other (2022 – $6 million).

### Cash Flow from Financing Activities

Net cash provided by financing activities decreased $616 million to $939 million for the year ended December 31, 2023, compared to $1,555 million in 2022. This decrease was due to lower proceeds from long-term debt at TEC, higher repayment of short-term debt at TEC, lower proceeds from short-term debt at TECO Finance and Emera, and higher repayments of committed credit facilities at NSPI. This was partially offset by proceeds from long-term debt at PGS and NSPI, retirement of long-term debt at TEC in 2022, and higher issuance of common stock.

## WORKING CAPITAL

As at December 31, 2023, Emera's cash and cash equivalents were $567 million (2022 – $310 million) and Emera's investment in non-cash working capital was $831 million (2022 – $1,173 million). Of the cash and cash equivalents held at December 31, 2023, $482 million was held by Emera's foreign subsidiaries (2022 – $250 million). A portion of these funds are invested in countries that have certain exchange controls, approvals, and processes for repatriation. Such funds are available to fund local operating and capital requirements unless repatriated.

## CONTRACTUAL OBLIGATIONS

As at December 31, 2023, contractual commitments 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 |
|---|---|---|---|---|---|---|---|
| Long-term debt principal | $ 1,670 | $ 264 | $ 3,047 | $ 666 | $ 525 | $ 12,318 | $ 18,490 |
| Interest payment obligations (1) | 836 | 807 | 719 | 626 | 587 | 7,438 | 11,013 |
| Transportation (2) | 696 | 495 | 405 | 388 | 338 | 2,597 | 4,919 |
| Purchased power (3) | 274 | 249 | 263 | 312 | 312 | 3,435 | 4,845 |
| Fuel, gas supply and storage | 556 | 215 | 62 | – | 5 | – | 838 |
| Capital projects | 778 | 111 | 70 | 1 | – | – | 960 |
| Asset retirement obligations | 10 | 2 | 1 | 1 | 2 | 407 | 423 |
| Pension and post-retirement obligations (4) | 28 | 29 | 38 | 47 | 32 | 155 | 329 |
| Equity investment commitments (5) | 240 | – | – | – | – | – | 240 |
| Other | 154 | 147 | 56 | 46 | 35 | 221 | 659 |
| | $ 5,242 | $ 2,319 | $ 4,661 | $ 2,087 | $ 1,836 | $ 26,571 | $ 42,716 |

(1) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2023, including any expected required payment under associated swap agreements.
(2) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $134 million related to a gas transportation contract between PGS and SeaCoast through 2040.
(3) Annual requirement to purchase electricity production from IPPs or other utilities over varying contract lengths.
(4) The estimated contractual obligation is calculated as the current legislatively required contributions to the registered funded pension plans (excluding the possibility of wind-up), plus the estimated costs of further benefit accruals contracted under NSPI's Collective Bargaining Agreement and estimated benefit payments related to other unfunded benefit plans.
(5) Emera has a commitment to make equity contributions to the LIL related to an investment true up in 2024 and sustaining capital contributions over the life of the partnership. The commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation the Maritime Link and LIL which is expected to be approximately $240 million in 2024. In addition, Emera has future commitments to provide sustaining capital to the LIL for routine capital and major maintenance.

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 February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion. In December 2023, the UARB approved collection of up to $164 million from NSPI for 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.

Construction of the LIL is complete and the Newfoundland Electrical System Operator confirmed the asset to be operating suitably to support reliable system operation and full functionality at 700MW, which was validated by the Government of Canada's Independent Engineer issuing its Commissioning Certificate on April 13, 2023.

Emera has committed to obtain certain transmission rights for Nalcor, if requested, to enable it to transmit energy which is not otherwise used in Newfoundland and Labrador or Nova Scotia. Nalcor has the right to transmit this energy from Nova Scotia to New England energy markets effective August 15, 2021 and continuing for 50 years. As transmission rights are contracted, the obligations are included within "Other" in the above table.

## FORECASTED CONSOLIDATED CAPITAL EXPENDITURES

The 2024 forecasted consolidated capital investments are as follows:

| millions of dollars | Florida Electric Utility | Canadian Electric Utilities | Gas Utilities and Infrastructure | Other Electric Utilities | Other | Total |
|---|---|---|---|---|---|---|
| Generation | $ 266 | $ 143 | $ - | $ 30 | $ - | $ 439 |
| New renewable generation | 280 | – | – | – | – | 280 |
| Electric transmission | 119 | 88 | – | – | – | 207 |
| Electric distribution | 496 | 142 | – | 58 | – | 696 |
| Gas transmission and distribution | – | – | 566 | – | – | 566 |
| Facilities, equipment, vehicles, and other | 567 | 63 | 51 | 17 | 4 | 702 |
| | $ 1,728 | $ 436 | $ 617 | $ 105 | $ 4 | $ 2,890 |

## DEBT MANAGEMENT

In addition to funds generated from operations, Emera and its subsidiaries have, in aggregate, access to committed syndicated revolving and non-revolving bank lines of credit in either CAD or USD per the table below.

| millions of Canadian dollars (unless otherwise indicated) | **Maturity** | **Credit Facilities** | **Utilized** | **Undrawn and Available** |
|---|---|---|---|---|
| Emera – Unsecured committed revolving credit facility | June 2027 | $ 900 | $ 265 | $ 635 |
| TEC (in USD) – Unsecured committed revolving credit facility | December 2026 | 800 | 707 | 93 |
| NSPI – Unsecured committed revolving credit facility | December 2027 | 800 | 332 | 468 |
| Emera – Unsecured non-revolving facility | December 2024 | 400 | 400 | – |
| Emera – Unsecured non-revolving facility | February 2024 | 400 | 200 | 200 |
| Emera – Unsecured non-revolving facility | August 2024 | 400 | 400 | – |
| TECO Finance (in USD) – Unsecured committed revolving credit facility | December 2026 | 400 | 185 | 215 |
| NSPI – Unsecured non-revolving facility | July 2024 | 400 | 400 | – |
| PGS (in USD) – Unsecured revolving facility | December 2028 | 250 | 55 | 195 |
| TEC (in USD) – Unsecured revolving facility | February 2024 | 200 | – | 200 |
| TEC (in USD) – Unsecured revolving facility | April 2024 | 200 | – | 200 |
| NMGC (in USD) – Unsecured revolving credit facility | December 2026 | 125 | 21 | 104 |
| NMGC (in USD) – Unsecured non-revolving facility | March 2024 | 23 | 23 | – |
| Other (in USD) – Unsecured committed revolving credit facilities | Various | 21 | 6 | 15 |

Emera and its subsidiaries have certain financial and other covenants associated with their debt and credit facilities. Covenants are tested regularly, and the Company is in compliance with covenant requirements as at December 31, 2023. Emera's significant covenant is listed below:

| | **Financial Covenant** | **Requirement** | **As at December 31, 2023** |
|---|---|---|---|
| **Emera** | | | |
| Syndicated credit facilities | Debt to capital ratio | Less than or equal to 0.70 to 1 | 0.57 : 1 |

Recent significant financing activity for Emera and its subsidiaries are discussed below by segment:

### Florida Electric Utilities

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. Therefore, $497 million USD of short-term borrowings that was repaid was classified as long-term debt at December 31, 2023.

On November 24, 2023, TEC repaid its $400 million USD unsecured non-revolving facility, which expired on December 13, 2023.

On April 3, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on April 1, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term secured overnight financing rate ("SOFR"), Wells Fargo's prime rate, the federal funds rate or the one-month SOFR, plus a margin. Proceeds from this facility will be used for general corporate purposes.

On March 1, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on February 28, 2024. The credit facility contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term SOFR, the Bank of Nova Scotia's prime rate, the federal funds rate or the one-month SOFR, plus a margin. Proceeds from this facility will be used for general corporate purposes.

### Canadian Electric Utilities

On March 24, 2023, NSPI issued $500 million in unsecured notes. The issuance included $300 million unsecured notes that bear interest at 4.95 per cent with a maturity date of November 15, 2032, and $200 million unsecured notes that bear interest at 5.36 per cent with a maturity date of March 24, 2053. Proceeds from these issuances were added to the general funds of the Company and applied primarily to refinance existing indebtedness, to finance capital investment and for general corporate purposes.

### Gas Utilities and Infrastructure

On December 19, 2023, PGS completed an issuance of $925 million USD in senior notes. The issuance included $350 million USD senior notes that bear interest at 5.42 per cent with a maturity date of December 19, 2028, $350 million USD senior notes that bear interest at 5.63 per cent with a maturity date of December 19, 2033 and $225 million USD senior notes that bear interest at 5.94 per cent with a maturity date of December 19, 2053. Proceeds from these issuances were used to settle intercompany loan agreements with TEC for the assets and liabilities transferred to PGS as part of the reorganization of the gas division of Tampa Electric, effective on January 1, 2023.

On December 1, 2023, PGS entered into a $250 million USD senior unsecured revolving credit facility with a group of banks, maturing on December 1, 2028. PGS has the ability to request the lenders to increase their commitments under the credit facility by up to $100 million USD in the aggregate subject to agreement from participating lenders. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. Proceeds from these facilities will be used for general corporate purposes.

On October 19, 2023, NMGC issued $100 million USD in senior unsecured notes that bear interest at 6.36 per cent with a maturity date of October 19, 2033. Proceeds from the issuance were used to repay short-term borrowings.

### Other Electric Utilities

On May 24, 2023, GBPC issued a $28 million USD non-revolving term loan that bears interest at 4.00 per cent with a maturity date of May 24, 2028. Proceeds from this issuance were used to repay GBPC's $28 million USD bond, which matured in May 2023.

### Other

On December 16, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from December 16, 2023 to December 16, 2024. There were no other changes in commercial terms from the prior agreement.

On August 18, 2023, Emera entered into a $400 million non-revolving term facility which matures on February 19, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. Proceeds from this facility will be used for general corporate purposes. On February 16, 2024, Emera extended the term of this agreement to a maturity date of February 19, 2025.

On June 30, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from August 2, 2023 to August 2, 2024. There were no other changes in commercial terms from the prior agreement.

On May 2, 2023, Emera issued $500 million in senior unsecured notes that bear interest at 4.84 per cent with a maturity date of May 2, 2030. The proceeds were used to repay Emera's $500 million unsecured fixed rate notes, which matured in June 2023.

## CREDIT RATINGS

Emera and its subsidiaries have been assigned the following senior unsecured debt ratings:

| | Fitch | S&P | Moody's | DBRS |
|---|---|---|---|---|
| Emera Inc. | BBB (Negative) | BBB- (Negative) | Baa3 (Negative) | N/A |
| TEC | A (Negative) | BBB+ (Negative) | A3 (Negative) | N/A |
| PGS (1) | A (Negative) | N/A | N/A | N/A |
| NMGC | BBB+ (Negative) | N/A | N/A | N/A |
| NSPI | N/A | BBB- (Negative) | N/A | BBB (high)(stable) |

(1) On November 10, 2023 Fitch Ratings ("Fitch") assigned first-time long-term issuer default rating of 'A-' to PGS and an instrument rating of 'A' for its private placements of senior unsecured bonds.

## GUARANTEED DEBT

As of December 31, 2023, the Company had $2.75 billion USD (2022 – $2.75 billion USD) senior unsecured notes ("US Notes") outstanding.

The US Notes are fully and unconditionally guaranteed, on a joint and several basis, by Emera and Emera US Holdings Inc. (in such capacity, the "Guarantor Subsidiaries"). Emera owns, directly or indirectly, all of the limited and general partnership interests in Emera US Finance LP. Other subsidiaries of the Company do not guarantee the US Notes (such subsidiaries are referred to as the "Non-Guarantor Subsidiaries"); however, Emera has unrestricted access to the assets of consolidated entities.

In compliance with Rule 13-01 of Regulation S-X, the Company is including summarized financial information for Emera, Emera US Holdings Inc., and Emera US Finance LP (together, the "Obligor Group"), on a combined basis after transactions and balances between the combined entities have been eliminated. Investments in and equity earnings of the Non-Guarantor Subsidiaries have been excluded from the summarized financial information.

The Obligor Group was not determined using geographic, service line or other similar criteria and, as a result, the summarized financial information includes portions of Emera's domestic and international operations. Accordingly, this basis of presentation is not intended to present Emera's financial condition or results of operations for any purpose other than to comply with the specific requirements for guarantor reporting.

### Summarized Statement of Income (Loss)

The Company recognized income related to guaranteed debt under the following categories:

| For the<br>millions of dollars | Year ended December 31<br>**2023** | <br>2022 |
|---|---|---|
| Loss from operations | **$ (62)** | $ (73) |
| Net gains (losses) (1) | **$ 349** | $ (131) |

(1) Includes $750 million (2022 – $262 million) in interest and dividend income, net, from non-guarantor subsidiaries.

### Summarized Balance Sheet

The Company has the following categories on the balance sheet related to guaranteed debt:

| As at<br>millions of dollars | December 31<br>2023 | 2022 |
|---|---|---|
| Current assets (1) | **$ 223** | $ 172 |
| Goodwill | **5,871** | 6,012 |
| Other assets (2) | **6,243** | 6,402 |
| Total assets (3) | **$ 12,337** | $ 12,586 |
| Current liabilities (4) | **$ 1,451** | $ 1,903 |
| Long-term liabilities (5) | **6,815** | 6,431 |
| Total liabilities | **$ 8,266** | $ 8,334 |

(1) Includes $179 million (2022 – $144 million) in amounts due from non-guarantor subsidiaries.
(2) Includes $5,941 million (2022 – $6,058 million) in amounts due from non-guarantor subsidiaries.
(3) Excludes investments in non-guarantor subsidiaries. Consolidated Emera total assets are $39,480 million (2022 – $39,742 million).
(4) Includes $411 million (2022 – $392 million) due to non-guarantor subsidiaries.
(5) Includes $619 million (2022 – $769 million) due to non-guarantor subsidiaries.

## OUTSTANDING STOCK DATA

### Common Stock

| **Issued and outstanding:** | millions of shares | millions of dollars |
|---|---|---|
| Balance, December 31, 2022 | 269.95 | $ 7,762 |
| Issuance of common stock under ATM program (1) | 8.29 | 397 |
| Issued under the DRIP, net of discounts | 5.26 | 272 |
| Senior management stock options exercised and Employee Share Purchase Plan | 0.62 | 31 |
| **Balance, December 31, 2023** | **284.12** | **$ 8,462** |

(1) For the year ended December 31,2023, 8,287,037 common shares were issued under Emera's ATM program at an average price of $48.27 per share for gross proceeds of $400 million ($397 million net of after-tax issuance costs). As at December 31,2023, an aggregate gross sales limit of $200 million remained available for issuance under the ATM program.

As at February 20, 2024, the amount of issued and outstanding common shares was 285.8 million.

If all outstanding stock options were converted as at February 20, 2024, an additional 3.1 million common shares would be issued and outstanding.

### ATM Equity Program

On October 3, 2023, Emera filed a short form base shelf prospectus, primarily in support of the renewal of its ATM Program in Q4 2023 that will allow the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. This ATM Program is expected to remain in effect until November 4, 2025.

### Preferred Stock

As at February 20, 2024, Emera had the following preferred shares issued and outstanding: Series A – 4.9 million; Series B – 1.1 million; Series C – 10.0 million; Series E – 5.0 million; Series F – 8.0 million; Series H – 12.0 million; Series J – 8.0 million, and Series L – 9.0 million. Emera's preferred shares do not have voting rights unless the Company fails to pay, in aggregate, eight quarterly dividends.

On July 6, 2023, Emera announced it would not redeem the 10 million outstanding Cumulative Rate Reset Preferred Shares, Series C ("Series C Shares") or the 12 million outstanding Cumulative Minimum Rate Reset First Preferred Shares, Series H ("Series H Shares") on August 15, 2023.

On August 4, 2023, Emera announced after having taken into account all conversion notices received from holders, no Series C Shares were converted into Cumulative Floating Rate First Preferred Shares, Series D Shares and no Series H shares were converted into Cumulative Floating Rate First Preferred Shares, Series I shares. The holders of the Series C Shares are entitled to receive a dividend of 6.434 per cent per annum on the Series C Shares during the five-year period commencing on August 15, 2023, and ending on (and inclusive of) August 14, 2028 ($0.40213 per Series C Share per quarter). The holders of the Series H Shares are entitled to receive a dividend of 6.324 per cent per annum on the Series H Shares during the five-year period commencing on August 15, 2023, and ending on (and inclusive of) August 14, 2028 ($0.39525 per Series H Share per quarter).

# Pension Funding

For funding purposes, Emera determines required contributions to its largest defined benefit ("DB") pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three-year period. Expected cash flow for DB pension plans is $34 million in 2024 (2023 – $42 million). All pension plan contributions are tax deductible and will be funded with cash from operations.

Emera's DB pension plans employ a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return, given the Company's goal of preserving capital with an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation, pension assets are managed by external investment managers per each pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of domestic and global equities, domestic and global bonds and short-term investments. The Company reviews investment manager performance on a regular basis and adjusts the plans' asset mixes as needed in accordance with the pension plans' investment policy.

Emera's projected contributions to defined contribution pension plans are $46 million for 2024 (2023 – $45 million).

## DEFINED BENEFIT PENSION PLAN SUMMARY

in millions of dollars

| Plans by region | TECO Energy | NSPI | Caribbean | Total |
|---|---|---|---|---|
| Assets as at December 31, 2023 | $ 907 | $ 1,381 | $ 10 | $ 2,298 |
| Accounting obligation at December 31, 2023 | $ 896 | $ 1,361 | $ 16 | $ 2,273 |
| Accounting expense (income) during fiscal 2023 | $ 4 | $ (16) | $ 1 | $ (11) |

# Off-Balance Sheet Arrangements

## DEFEASANCE

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide principal and interest streams to match the related defeased debt, which at December 31, 2023 totalled $200 million (2022 – $200 million). The securities are held in trust for an affiliate of the Province of Nova Scotia. Approximately 66 per cent of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio.

## GUARANTEES AND LETTERS OF CREDIT

Emera has guarantees and letters of credit on behalf of third parties outstanding. The following significant guarantees and letters of credit are not included within the Consolidated Balance Sheets as at December 31, 2023:

TECO Energy has issued a guarantee in connection with SeaCoast's performance of obligations under a gas transportation precedent agreement. The guarantee is for a maximum potential amount of $45 million USD if SeaCoast fails to pay or perform under the contract. The guarantee expires five years after the gas transportation precedent agreement termination date, which was terminated on January 1, 2022. In the event TECO Energy's and Emera's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would be required to provide its counterparty a letter of credit or cash deposit of $27 million USD.

TECO Energy issued a guarantee in connection with SeaCoast's performance obligations under a firm service agreement, which expires December 31, 2055, subject to two extension terms at the option of the counterparty with a final expiration date of December 31, 2071. The guarantee is for a maximum potential amount of $13 million USD if SeaCoast fails to pay or perform under the firm service agreement. In the event that TECO Energy's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would need to provide either a substitute guarantee from an affiliate with an investment grade credit rating or a letter of credit or cash deposit of $13 million USD.

Emera Inc. has issued a guarantee of $66 million USD relating to outstanding notes of ECI. This guarantee will automatically terminate on the date upon which the obligations have been repaid in full.

NSPI has issued guarantees on behalf of its subsidiary, NS Power Energy Marketing Incorporated, in the amount of $104 million USD (2022 – $119 million USD) with terms of varying lengths.

The Company has standby letters of credit and surety bonds in the amount of $103 million USD (December 31, 2022 – $145 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one-year term and are renewed annually as required.

Emera 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 2024. The amount committed as at December 31, 2023 was $56 million (December 31, 2022 – $63 million).

## Dividend Payout Ratio

Emera has provided annual dividend growth guidance of four to five per cent through 2026. The Company targets a long-term dividend payout ratio of adjusted net income of 70 to 75 per cent and, while the payout ratio is likely to exceed that target through and beyond the forecast period, it is expected to return to that range over time. Emera's common share dividends paid in 2023 were $2.7875 ($0.6900 in Q1, Q2, and Q3 and $0.7175 in Q4) per common share and $2.6775 ($0.6625 in Q1, Q2, and Q3 and $0.6900 in Q4) per common share for 2022, representing a dividend payout ratio of 78 per cent in 2023 (2022 – 75 per cent) and a dividend payout ratio of adjusted net income of 94 per cent in 2023 (2022 – 83 per cent).

On September 20, 2023, the Board approved an increase in the annual common share dividend rate to $2.87 from $2.76 per common share. The first quarterly dividend payment at the increased rate was paid on November 15, 2023.

## Transactions with Related Parties

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 Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $163 million for the year ended December 31, 2023 (2022 – $157 million). NSPML is accounted for as an equity investment, and therefore corresponding earnings related to this revenue are reflected in Income from equity investments. For further details, refer to the "Business Overview and Outlook – Canadian Electric Utilities – ENL" and "Contractual Obligations" sections.
- Natural gas transportation capacity purchases from M&NP are reported in the Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $14 million for the year ended December 31, 2023 (2022 – $9 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Consolidated Balance Sheets as at December 31, 2023 and at December 31, 2022.

# Enterprise Risk and Risk Management

Emera has an enterprise-wide risk management process, overseen by its Enterprise Risk Management Committee ("ERMC") and monitored by the Board, to ensure an effective, consistent and coherent approach to risk management. Certain risk management activities for Emera are overseen by the ERMC to ensure such risks are appropriately identified, assessed, monitored and subject to appropriate controls.

The Board has a Risk and Sustainability Committee ("RSC") with a mandate to assist the Board in carrying out its risk and sustainability oversight responsibilities. The RSC's mandate includes oversight of the Company's Enterprise Risk Management framework, including the identification, assessment, monitoring and management of enterprise risks. It also includes oversight of the Company's approach to sustainability and its performance relative to its sustainability objectives.

The Company's financial risk management activities are focused on those areas that most significantly impact profitability, quality and consistency of income, and cash flow. Emera's risk management focus extends to key operational risks including safety and environment, which represent core values of Emera. In this section, Emera describes the principal risks that management believes could materially affect its business, revenues, operating income, net income, net assets, liquidity or capital resources. The nature of risk is such that no list is comprehensive, and other risks may arise or risks not currently considered material may become material in the future.

## REGULATORY AND POLITICAL RISK

The Company's rate-regulated subsidiaries and certain investments subject to significant influence are subject to risk of the recovery of costs and investments. Regulatory and political risk can include changes in regulatory frameworks, shifts in government policy, legislative changes, and regulatory decisions.

As cost-of-service utilities with an obligation to serve customers, Emera's utilities operate under formal regulatory frameworks, and must obtain regulatory approval to change or add rates and/or riders. Emera also holds investments in entities in which it has significant influence, and which are subject to regulatory and political risk including NSPML, LIL, and M&NP. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the CER on a complaint basis, as opposed to the regulatory approval process described above. In the absence of a complaint, the CER does not normally undertake a detailed examination of Brunswick Pipeline's tolls, which are subject to a firm service agreement, expiring in 2034, with Repsol Energy North America Canada Partnership.

Regulators administer the regulatory frameworks covering material aspects of the utilities' businesses, including applying market-based tests to determine the appropriate customer rates and/or riders, the underlying allowed ROEs, deemed capital structures, capital investment, the terms and conditions for the provision of service, performance standards, and affiliate transactions. Regulators also review the prudency of costs and other decisions that impact customer rates and reliability of service and work to ensure the financial health of the utility for the benefit of customers. Costs and investments can be recovered upon approval by the respective regulator as an adjustment to rates and/or riders, which normally require a public hearing process or may be mandated by other governmental bodies. During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these rate-regulated companies, and their respective regulators determine whether to allow recovery and to adjust rates based upon the evidence and any contrary evidence from other parties. In some circumstances, other government bodies may influence the setting of rates. Regulatory decisions, legislative changes, and prolonged delays in the recovery of costs or regulatory assets could result in decreased rate affordability for customers and could materially affect Emera and its utilities.

Emera's utilities generally manage this risk through transparent regulatory disclosure, ongoing stakeholder and government consultation, and multi-party engagement on aspects such as utility operations, regulatory audits, rate filings and capital plans. The subsidiaries work to establish collaborative relationships with regulatory stakeholders, including customer representatives, both through its approach to filings and additional efforts with technical conferences and, where appropriate, negotiated settlements.

Changes in government and shifts in government policy and legislation can impact the commercial and regulatory frameworks under which Emera and its subsidiaries operate. This includes initiatives regarding deregulation or restructuring of the energy industry. Deregulation or restructuring of the energy industry may result in increased competition and unrecovered costs that could adversely affect the Company's operations, net income and cash flows. State and local policies in some United States jurisdictions have sought to prevent or limit the ability of utilities to provide customers the choice to use natural gas while in other jurisdictions policies have been adopted to prevent limitations on the use of natural gas. Changes in applicable state or local laws and regulations, including electrification legislation, could adversely impact PGS and NMGC.

Emera cannot predict future legislative, policy, or regulatory changes, whether caused by economic, political or other factors, or its ability to respond in an effective and timely manner or the resulting compliance costs. Government interference in the regulatory process can undermine regulatory stability, predictability, and independence, and could have a material adverse effect on the Company.

## GLOBAL CLIMATE CHANGE RISK

The Company is subject to risks that may arise from the impacts of climate change. There is increasing public concern about climate change and growing support for reducing carbon dioxide emissions. Municipal, state, provincial and federal governments have been setting policies and enacting laws and regulations to deal with climate change impacts in a variety of ways, including decarbonization initiatives and promotion of cleaner energy and renewable energy generation of electricity. Refer to "Changes in Environmental Legislation" risk below. Insurance companies have begun to limit their exposure to coal-fired electricity generation and are evaluating the medium and long-term impacts of climate change which may result in fewer insurers, more restrictive coverage and increased premiums. Refer to the "Insurance" section below and "Uninsured Risk".

Climate change may lead to increased frequency and intensity of events and related impacts such as hurricanes, ice and other storms, heavy rainfall, cyclones, extreme winds, wildfires, flooding and droughts. The potential impacts of climate change, such as rising sea levels and larger storm surges from more intense hurricanes, can combine to produce even greater damage to coastal generation and other facilities. Climate change is also characterized by rising global temperatures. Increased air temperatures may bring increased frequency and severity of wildfires within the Company's service territories. Refer to "Weather Risk" and "System Operating and Maintenance Risks".

The Company's long-term capital investment plan includes significant investment across the portfolio in renewable and cleaner generation, infrastructure modernization, storm hardening, energy storage and customer-focused technologies. All these initiatives contribute toward mitigating the potential impacts of climate change. The Company continues to engage with government, regulators, industry partners and stakeholders to share information and participate in the development of climate change related policies and initiatives.

### Physical Impacts:

The Company is subject to physical risks that arise, or may arise, from global climate change, including damage to operating assets from more frequent and intense weather events and from wildfires due to warming air temperatures and increasing drought conditions. Substantially all of the Company's fossil fueled generation assets are located at or near coastal sites and, as such, are exposed to the separate and combined effects of rising sea levels and increasing storm intensity, including storm surges and flooding. Refer to "Weather Risk" for further information.

These risks are mitigated to an extent through features such as flood walls at certain plants and through the location of plants on higher ground. Planned investments in under-grounding parts of the electricity infrastructure contribute to risk mitigation, as does insurance coverage (for assets other than electricity transmission and distribution assets). In addition, implementation of regulatory mechanisms for recovery of costs, such as storm reserves and regulatory deferral accounts, help smooth out the recovery of storm restoration costs over time.

**Reputation:**

Failure to address issues related to climate change could affect Emera's reputation with stakeholders, its ability to operate and grow, and the Company's access to, and cost of, capital. Refer to "Liquidity and Capital Market Risk". The Company seeks to mitigate this in part by moving away from higher-carbon generation in favour of lower-carbon generation and non-emitting renewable generation.

**Supply Chain:**

Changing carbon-related costs, policy and regulatory changes and shifts in supply and demand factors could lead to more expensive or more scarce products and services that are required by the Company in its operations. This could lead to supply shortages, delivery delays and the need to source alternate products and services. The Company seeks to mitigate these risks through close monitoring of such developments and adaptive changes to supply chain procurement strategies. Refer to "Supply Chain Risk" and "Uninsured Risk".

**Insurance:**

Given concerns regarding carbon-emitting generation, assets and businesses may, over time, become difficult (or uneconomic) to insure in commercial insurance markets. In the short term, this may be mitigated through increased investment in engineered protection or alternative risk financing (such as funded self-insurance or regulatory structures, including storm reserves). Longer-term mitigation may be achieved through infrastructure siting decisions and further engineered protections. This risk may also be mitigated through the continued transition away from high-carbon generation sources to sources with low or zero carbon dioxide emissions.

**Policy:**

Government and regulatory initiatives, including greenhouse gas emissions standards, air emissions standards and generation mix standards, are being proposed and adopted in many jurisdictions in response to concerns regarding the effects of climate change. In some jurisdictions, government policy has included timelines for mandated shutdowns of coal generating facilities, percentage of electricity generation from renewables, carbon pricing, emissions limits and cap and trade mechanisms. Over the medium and longer terms, this could potentially lead to a significant portion of hydrocarbon infrastructure assets being subject to additional regulation and limitations in respect of GHG emissions and operations.

The Company is subject to climate-related and environmental legislative and regulatory requirements. Such legislative and regulatory initiatives could adversely affect Emera's operations and financial performance. Refer to "Regulatory and Political Risk" and "Changes in Environmental Legislation" risk. The Company seeks to mitigate these risks through active engagement with governments and regulators to pursue transition strategies that meet the needs of customers, stakeholders and the Company. This has included NSPI's participation in negotiated equivalency agreements in Nova Scotia to provide for an affordable transition to lower-carbon generation. Equivalency agreements allow NSPI to achieve compliance with federal GHG emissions regulations by meeting provincial legislative and regulatory requirements as they are deemed to be equivalent. There is no guarantee that such equivalency agreements will be renewed or remain in force in the future.

**Regulatory:**

Depending on the regulatory response to government legislation and regulations, the Company may be exposed to the risk of reduced recovery through rates in respect of the affected assets. Valuation impairments could result from such regulatory outcomes. Mitigation efforts in respect of these risks include active engagement with policy makers and regulators to find mechanisms to avoid such impacts while being responsive to customers' and stakeholders' objectives.

**Legal:**

The Company could face litigation or regulatory action related to environmental harms from carbon dioxide emissions or climate change public disclosure issues. The Company addresses these risks through compliance with all relevant laws, emissions reduction strategies, and public disclosure of climate change risks.

**Water Resources:**

For thermal plants requiring cooling water, reduced availability of water resulting from climate change could adversely impact operations or the costs of operations. The Company seeks ways to reduce and recycle water as it does in its Polk power plant in Florida, where recovered and treated wastewater is used in operations to reduce reliance on fresh water supplies in an area where water is not as abundant as in other markets.

The Company operates hydroelectric generation in certain of its markets. Such generation depends on availability of water and the hydrological profile of water sources. Changes in precipitation patterns, water temperatures and air temperatures could adversely affect the availability of water and consequently the amount of electricity that may be produced from such facilities. The Company is reinvesting in the efficiency of certain hydroelectric generation facilities to increase generation capacity and continues to monitor changing hydrology patterns. Such issues may also affect the availability of purchased power from third-party owned hydroelectricity sources.

## WEATHER RISK

The Company is subject to risks that arise or may arise from weather including seasonal variations impacting energy sales, more frequent and intense weather events, changing air temperatures, wildfires and extreme weather conditions associated with climate change. Refer to "Global Climate Change Risk".

Fluctuations in the amount of electricity or natural gas used by customers can vary significantly in response to seasonal changes in weather and could impact the operations, results of operations, financial condition, and cash flows of the Company's utilities. For example, TEC could see lower demand in summer months if temperatures are cooler than expected. Further, extreme weather conditions such as hurricanes and other severe weather conditions which may be associated with climate change could cause these seasonal fluctuations to be more pronounced. In the absence of a regulatory recovery mechanism for unanticipated costs, such events could influence the Company's results of operations, financial conditions or cash flows.

Extreme weather events create a risk of physical damage to the Company's assets. High winds can impact structures and cause widespread damage to transmission and distribution infrastructure, solar generation, and wind powered generation. Higher frequency and severity of weather events increase the likelihood of longer power outages and more fuel supply disruptions. Increased frequency and intensity of flooding and storm surge could adversely affect the operations of utilities and in particular generation assets. The impact of extreme weather events would be amplified if the same events affect multiple utilities.

Each of Emera's regulated electric utilities have programs for storm hardening of transmission and distribution facilities to minimize damage, but there can be no assurance that these measures will fully mitigate the risk. This risk to transmission and distribution facilities is typically not insured, and as such the restoration cost is generally recovered through regulatory processes, either in advance through reserves or designated self-insurance funds, or after the fact through the establishment of regulatory assets. Recovery is not assured and is subject to prudency review. The risk to generation assets is, in part, mitigated through the design, siting, construction and maintenance of such facilities, regular risk assessments, engineered mitigation, emergency storm response plans, and insurance.

High winds and lack of precipitation increase the risk of wildfires resulting from the Company's infrastructure or for which the Company may otherwise have responsibility. The risk of wildfires is addressed primarily through asset management programs for natural gas transmission and distribution operations, and asset management, storm hardening, and vegetation management programs for electric utilities, but there can be no assurance that these measures will fully mitigate the risk. If it is found to be responsible for such a fire, the Company could suffer material costs, losses and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes. If not recovered through these means, they could materially affect Emera's business, access to capital, financial condition and results of operations including its reputation with customers, regulators, governments and financial markets. Resulting costs could include fire suppression costs, regeneration, timber value, increased insurance costs and costs arising from damages and losses incurred by third parties.

## CHANGES IN ENVIRONMENTAL LEGISLATION

Emera is subject to regulation by federal, provincial, state, regional and local authorities regarding environmental matters, primarily related to its utility operations. This includes laws setting GHG emissions standards and air emissions standards. Emera is also subject to laws regarding waste management, wastewater discharges and aquatic and terrestrial habitats.

Changes to GHG emissions standards and air emissions standards could adversely affect Emera's operations and financial performance.

Both the Government of Nova Scotia and the Government of Canada have enacted or introduced legislation that includes goals of net-zero GHG emissions by 2050. The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI's generation mix, reductions in GHG emissions, as well as the goal to phase out coal-fired electricity generation by 2030. Failure to meet such goals by 2030 could result in material fines, penalties, other sanctions and adverse reputational impacts. NSPI continues to work with both the provincial and federal governments on measures to seek to address their carbon reduction goals. Within Emera's natural gas utilities, there are ongoing efforts to reduce methane and carbon dioxide emissions through replacement of aging infrastructure, more efficient operations, operational and supply chain optimization, renewable natural gas projects, and support of public policy initiatives that address the effects of climate change.

In 2023, the United States Environmental Protection Agency proposed new carbon emission standards for fossil fuel-fired power plants and the Government of Canada released draft Clean Electricity Regulations which propose limitations on the use of natural gas generation. Until final rules are issued, it is not certain what the impact will be on the Company and its operations.

These and other legislative or regulatory changes could influence decisions regarding capital investment, early retirement of generation facilities and may result in stranded costs if the Company is not able to fully recover the costs and investment in the affected generation assets. Recovery is not assured and is subject to prudency review. Legislative or regulatory changes may curtail sales of natural gas to new customers, which could reduce future customer growth in Emera's natural gas businesses. Stricter environmental laws and enforcement of such laws in the future could increase Emera's exposure to additional liabilities and costs. These changes could also affect earnings and strategy by changing the nature and timing of capital investments.

Per- and polyfluoroalkyl substances ("PFAS") are man-made chemicals that are widely used in consumer products and can persist and bio-accumulate in the environment. The Company does not manufacture PFAS but because these emerging contaminants of concern are so ubiquitous in products and the environment, it may impact Emera's operations. Changes in environmental laws and regulations related to PFAS could result in new costs or obligations for investigation and cleanup and change the Company's strategy for land acquisition for projects such as solar generation.

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

Emera manages its environmental risk by operating in a manner that is respectful and protective of the environment and in compliance with applicable legal requirements and Company policy. Emera has implemented this policy through the development and application of environmental management systems in its operating subsidiaries. Comprehensive audit programs are in place to regularly assess compliance.

## CYBERSECURITY RISK

Emera is exposed to potential risks related to cyberattacks and unauthorized access. The Company relies on IT systems, cloud infrastructure, third-party service providers and the diligence of its team members to effectively manage and safely operate its assets. This includes controls for interconnected systems of generation, distribution and transmission as well as financial, billing and other enterprise systems. As the Company operates critical assets, it may be at greater risk of cyberattacks, which could include those from nation-state cyber threat actors. Major emerging and ongoing global conflicts may also elevate this risk.

Cyberattacks can reach the Company's assets and information via their interfaces with third parties or the public internet and gain access to critical infrastructures. Cyberattacks can also occur via personnel with access to critical assets or trusted networks. Methods used to attack critical assets could include generic or energy-sector-specific malware delivered via network transfer, removable media, attachments, or links in e-mails. The methods used by attackers are continuously evolving and can be difficult to predict and detect.

Despite security measures in place, that are described below, the Company's systems, assets and information could experience security breaches that could cause system failures, disrupt operations, or adversely affect safety. Such breaches could compromise customer, employee-related or other information systems and could result in loss of service to customers, unavailability of critical assets, safety issues, or the release, destruction, or misuse of critical, sensitive or confidential information. These breaches could also delay delivery or result in contamination or degradation of hydrocarbon products the Company transports, stores or distributes.

Cyberattacks or unauthorized accesses may cause lost revenues, costs, losses and damages all, or some of which, may not be recoverable (through insurance, legal, regulatory cost recovery or other processes). This could materially adversely affect Emera's business and financial results including its reputation with customers, regulators, governments and financial markets. Resulting costs could include, amongst others, response, recovery and remediation costs, increased protection or insurance costs and costs arising from damages and losses incurred by third parties. If any such security breaches occur, there is no assurance they can be adequately addressed in a timely manner.

The Company seeks to manage these risks by aligning to a common set of cybersecurity standards and policies derived, in part, on the National Institute of Standards and Technology's Cyber Security Framework, periodic security testing, program maturity objectives, cybersecurity incident readiness program, and employee communication and training. With respect to certain of its assets, the Company is required to comply with rules and standards relating to cybersecurity and IT including, but not limited to, those mandated by bodies such as the North American Electric Reliability Corporation, Northeast Power Coordinating Council, and the United States Department of Homeland Security. The status of key elements of the Company's cybersecurity program is reported to the RSC. The Board oversees risk and mitigation plans in relation to cybersecurity risks and receives a quarterly update in a risk dashboard at each regularly scheduled Board meeting.

## PUBLIC HEALTH RISK

An outbreak of infectious disease, a pandemic or a similar public health threat, or a fear of any of the foregoing, could adversely impact the Company, including causing operating, supply chain and project development delays and disruptions, labour shortages and shutdowns (including as a result of government regulation and prevention measures), which could have a negative impact on the Company's operations.

Any adverse changes in general economic and market conditions arising as a result of a public health threat could negatively impact demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; which could result in a material adverse effect on the Company's business. The Company maintains pandemic and business contingency plans in each of its operations to manage and help mitigate the impact of any such public health threat.

## ENERGY CONSUMPTION RISK

Emera's rate-regulated utilities are affected by demand for energy based on changing customer patterns due to fluctuations in a number of factors including general economic conditions, weather events, customers' focus on energy efficiency, changes in rates, and advancements in new technologies such as rooftop solar, electric vehicles and battery storage. Government policies promoting distributed generation, and new technology developments that enable those policies, have the potential to impact how electricity enters the system and how it is bought and sold. In addition, increases in distributed generation may impact demand resulting in lower load and revenues. These changes could negatively impact Emera's operations, rate base, net earnings, and cash flows. The Company's rate-regulated utilities are focused on understanding customer demand, energy efficiency, and government policy to ensure that the impact of these activities benefit customers, that they do not negatively impact the reliability of the energy service and that they are addressed through regulations.

## FOREIGN EXCHANGE RISK

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

Consistent with the Company's risk management policies, Emera manages currency risks through matching United States denominated debt to finance its United States operations and may use foreign currency derivative instruments to hedge specific transactions and earnings exposure. The Company may enter FX forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenue streams and capital expenditures, and on net income earned outside of Canada. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including FX.

The Company does not utilize derivative financial instruments for foreign currency trading or speculative purposes or to hedge the value of its investments in foreign subsidiaries. Exchange gains and losses on net investments in foreign subsidiaries do not impact net income as they are reported in Accumulated Other Comprehensive Income (Loss) ("AOCI") ("AOCL").

## LIQUIDITY AND CAPITAL MARKET RISK

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

Emera's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions and ratings assigned by various market analysts, including credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in PP&E and the risk associated with changes in interest rates could have an adverse effect on the cost of financing. The Company's future access to capital and cost of borrowing may be impacted by various market disruptions. The inability to access cost-effective capital could have a material impact on Emera's ability to fund its growth plan.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the Company's business, its regulatory framework and legislative environment, political interference in the regulatory process, the ability to recover costs and earn returns, diversification, leverage, liquidity and increased exposure to climate change-related impacts, including increased frequency and severity of hurricanes and other severe weather events. A decrease in a credit rating could result in higher interest rates in future financings, increased borrowing costs under certain existing credit facilities, limit access to the commercial paper market, or limit the availability of adequate credit support for subsidiary operations. For more information on interest rate risk, refer to "General Economic Risk – Interest Rate Risk". For certain derivative instruments, if the credit ratings of the Company were reduced below investment grade, the full value of the net liability of these positions could be required to be posted as collateral. Emera manages these risks by actively monitoring and managing key financial metrics with the objective of sustaining investment grade credit ratings.

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

## GENERAL ECONOMIC RISK

The Company has exposure to the macro-economic conditions in North America and in other geographic regions in which Emera operates. Like most utilities, economic factors such as consumer income, employment and housing affect demand for electricity and natural gas and, in turn, the Company's financial results. Adverse changes in general economic conditions and inflation may impact the ability of customers to afford rate increases arising from increases to fuel, operating, capital, environmental compliance, and other costs, and therefore could materially affect Emera and its utilities. This may also result in higher credit and counterparty risk, adverse shifts in government policy and legislation, and/or increased risk to full and timely recovery of costs and regulatory assets.

### Interest Rate Risk:

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk. Emera seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

For Emera's regulated subsidiaries, the cost of debt is a component of rates and prudently incurred debt costs are recovered from customers. Regulatory ROE will generally follow the direction of interest rates, such that regulatory ROEs are likely to fall in times of reducing interest rates and rise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

Interest rates could also be impacted by changes in credit ratings. For more information, refer to "Liquidity and Capital Market Risk".

As with most other utilities and other similar yield-returning investments, Emera's share price may be affected by changes in interest rates and could underperform the market in an environment of rising interest rates.

### Inflation Risk:

The Company may be exposed to changes in inflation that may result in increased operating and maintenance costs, capital investment, and fuel costs compared to the revenues provided by customer rates. Emera's utilities have budgeting and forecasting processes to identify inflationary risk factors and measure operating performance, as well as collective bargaining agreements that mitigate the short-term impact of inflation on labour costs of unionized employees.

## PROJECT DEVELOPMENT AND LAND USE RIGHTS RISK

The Company's capital plan includes significant investment in generation, infrastructure modernization, and customer-focused technologies. Any projects planned or currently in construction, particularly significant capital projects, may be subject to risks including, but not limited to, impact on costs from schedule delays, increased demand for renewable energy inputs, risk of cost overruns, ensuring compliance with operating and environmental requirements and other events within or beyond the Company's control. The Company's projects may also require approvals and permits at the federal, provincial, state, regional and local levels. There is no assurance that Emera will be able to obtain the necessary project approvals or applicable permits or receive regulatory approval to recover the costs in rates.

Some of the Company's assets are located on land owned by third parties, including Indigenous Peoples, and may be subject to land claims. Present or future assets may be located on lands that have been used for traditional purposes and therefore subject to specific consultations, consents, or conditions for development or operation. If the Company's rights to locate and operate its assets on any such lands are subject to expiry or become invalid, it may incur material costs to renew rights or obtain such rights. If reasonable terms for land-use rights cannot be negotiated, the Company may incur significant costs to remove and relocate its assets and restore the land. Additional costs incurred could cause projects to be uneconomical to proceed with.

Emera manages these project development and land use rights risks by deploying robust project and risk management approaches, led by teams with extensive experience in large projects. The Company consults with Indigenous Peoples in obtaining approvals, constructing, maintaining and operating such facilities, consistent with laws and public policy frameworks. Emera maintains relationships through on-going communications with stakeholders, including Indigenous Peoples, landowners and governments.

## COUNTERPARTY RISK

Emera is exposed to risk related to its reliance on certain key partners, suppliers, and customers, any of which may endure financial challenges resulting from commodity price and market volatility, economic instability or adversity, adverse political or regulatory changes and other causes which may cause or contribute to such parties' insolvency, bankruptcy, restructuring or default on their contractual obligations to Emera. Emera is also exposed to potential losses related to amounts receivable from customers, energy marketing collateral deposits and derivative assets due to a counterparty's non-performance under an agreement.

Emera manages this counterparty risk through due diligence and third-party risk assessment processes prior to signing contracts, contractual rights and remedies, regulatory frameworks, and by monitoring significant developments with its customers, partners and suppliers. The Company also manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments may be conducted on new customers and counterparties, and deposits or collateral may be requested on certain accounts. There is no assurance that management strategies will be effective, and significant counterparty defaults could have a material effect on the Company.

## COUNTRY RISK

The majority of Emera's earnings are from outside of Canada, mostly concentrated in the United States. Emera's investments are currently in regions where political and economic risks are considered by the Company to be acceptable. For more information, refer to the "Regulatory and Political Risk" and "General Economic Risk" sections above. Emera's operations in some countries may be subject to changes in economic growth, restrictions on the repatriation of income or capital exchange controls, inflation, the effect of global health, safety and environmental matters, including climate change, or economic conditions and market conditions, and change in financial policy and availability of credit. The Company mitigates this risk through a rigorous approval process for investment, and by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available in all affiliates.

## SUPPLY CHAIN RISK

Emera's ability to meet customer energy requirements, respond to storm-related disruptions and execute on our capital program in a cost-effective and timely manner are dependent on maintaining an efficient supply chain. Domestic and global supply chain issues may delay the delivery or result in shortages of certain materials, equipment and other resources that are critical to the Company's operations. These disruptions may be further exacerbated by inflationary pressures, labour shortages, government incentives increasing demand for clean energy projects, and the impact of international conflicts, tariffs, or other trade restrictions. Failure to eliminate or manage supply chain constraints may impact the availability and cost of items and labour that are necessary to support operations and capital investment. Emera continues to monitor the situation and seeks to mitigate the impacts of supply chain risk by securing alternative suppliers, third party risk management, modifying design standards, and adjusting the timing of work.

## COMMODITY PRICE RISK

The Company's utility fuel supply and purchase of other commodities is subject to commodity price risk. In addition, Emera Energy is subject to commodity price risk through its portfolio of commodity contracts and arrangements.

The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. These include the Company's commercial arrangements, such as the combination of supply and purchase agreements, asset management agreements, pipeline transportation agreements, and financial hedging instruments. In addition, its credit policies, counterparty credit assessments, market and credit position reporting, and other risk management and reporting practices, are also used to manage and mitigate this risk.

### Regulated Utilities:

The Company's utility fuel supply is exposed to broader global conditions, which may include impacts on delivery reliability and price, despite contracted terms. Supply and demand dynamics in fuel markets can be affected by a wide range of factors which are difficult to predict and may change rapidly, including but not limited to, currency fluctuations, changes in global economic conditions, natural disasters, transportation or production disruptions, and geo-political risks, such as political instability, conflicts, changes to international trade agreements, trade sanctions or embargos. The Company seeks to manage this risk using financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable.

The majority of Emera's regulated electric and gas utilities have adopted and implemented fuel adjustment mechanisms and purchased gas adjustment mechanisms respectively, which further helps manage commodity price risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel and gas costs. There is no assurance that such mechanisms and regulatory frameworks will continue to exist in the future. Prolonged and substantial increases in fuel prices could result in decreased rate affordability, increased risk of recovery of costs or regulatory assets, and/or negative impacts on customer consumption patterns and sales.

**Emera Energy Marketing and Trading:**

Emera Energy has employed further measures to manage commodity risk. The majority of Emera Energy's portfolio of electricity and gas marketing and trading contracts and, in particular, its natural gas asset management arrangements, are contracted on a back-to-back basis, avoiding any material long or short commodity positions. However, the portfolio is subject to commodity price risk, particularly with respect to basis point differentials between relevant markets in the event of an operational issue or counterparty default. Changes in commodity prices can also result in increased collateral requirements associated with physical contracts and financial hedges, resulting in higher liquidity requirements and increased costs to the business.

To measure commodity price risk exposure, Emera Energy employs a number of controls and processes, including an estimated VaR analysis of its exposures. The VaR amount represents an estimate of the potential change in FV that could occur from changes in Emera Energy's portfolio or changes in market factors within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with physical commodities, primarily natural gas and power positions.

## FUTURE EMPLOYEE BENEFIT PLAN PERFORMANCE AND FUNDING RISK

Emera subsidiaries have both defined benefit and defined contribution employee pension plans that cover their employees and retirees. All defined benefit plans are closed to new entrants, except for the TECO Energy Group Retirement Plan and the Grand Bahama Power Company Limited Union Employees' Pension Plan. The cost of providing these benefit plans varies depending on plan provisions, interest rates, inflation, investment performance and actuarial assumptions concerning the future. Actuarial assumptions include earnings on plan assets, discount rates (interest rates used to determine funding levels, contributions to the plans and the pension and post-retirement liabilities) and expectations around future salary growth, inflation and mortality. Three of the largest drivers of cost are investment performance, interest rates and inflation, which are affected by global financial and capital markets. Depending on future interest rates and future inflation and actual versus expected investment performance, Emera could be required to make larger contributions in the future to fund these plans, which could adversely affect Emera's cash flows, financial condition and operations.

Each of Emera's employee defined benefit pension plans are managed according to an approved investment policy and governance framework. Emera employs a long-term approach with respect to asset allocation and each investment policy outlines the level of risk which the Company is prepared to accept with respect to the investment of the pension funds in achieving both the Company's fiduciary and financial objectives. Studies are routinely undertaken approximately every five years with the objective that the plans' asset allocations are appropriate for meeting Emera's long-term pension objectives.

## LABOUR RISK

Emera's ability to deliver service to its customers and to execute its growth plan depends on attracting, developing and retaining a skilled workforce. Utilities are faced with demographic challenges related to trades, technical staff and engineers with an increasing number of employees expected to retire over the next several years. Failure to attract, develop and retain an appropriately qualified workforce could adversely affect the Company's operations and financial results. Emera seeks to manage this risk through maintaining competitive compensation programs, a dedicated talent acquisition team, human resources programs and practices, including ethics and diversity training, employee engagement surveys, succession planning for key positions and apprenticeship programs.

Approximately 30 per cent of Emera's labour force is represented by unions and subject to collective labour agreements. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labour costs and work disruptions, which could adversely affect service to customers and have an adverse effect on the Company's earnings, cash flow and financial position. Emera seeks to manage this risk through ongoing discussions and working to maintain positive relationships with local unions. The Company maintains contingency plans in each of its operations to manage and reduce the effect of any potential labour disruption.

## IT RISK

Emera relies on various IT systems to manage operations. This subjects Emera to inherent costs and risks associated with maintaining, upgrading, replacing and changing these systems. This includes impairment of its IT, potential disruption of internal control systems, substantial capital expenditures, demands on management time and other risks of delays, difficulties in upgrading existing systems, transitioning to new systems or integrating new systems into its current systems. Emera's digital transformation strategy, including investment in infrastructure modernization and customer focused technologies, is driving increased investment in IT solutions, resulting in increased project risks associated with the implementation of these solutions.

Emera manages these risks through IT asset lifecycle planning and management, governance, internal auditing and testing of systems, and executive oversight. Employees with extensive subject matter expertise assist in risk identification and mitigation, project management, implementation, change management and training. System resiliency, formal disaster recovery and backup processes, combined with critical incident response practices, table-top exercises, and simulations, help mitigate operational disruptions.

## INCOME TAX RISK

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the United States and the Caribbean. Any such changes could affect the Company's future earnings, cash flows, and financial position. The value of Emera's existing deferred income tax assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws. Emera monitors the status of existing tax laws to ensure that changes impacting the Company are appropriately reflected in the Company's tax compliance filings and financial results.

## SYSTEM OPERATING AND MAINTENANCE RISKS

The safe and reliable operation of electric generation and electric and natural gas transmission and distribution systems is critical to Emera's operations. There are a variety of hazards and operational risks inherent in operating electric utilities and natural gas transmission and distribution pipelines. Electric generation, transmission and distribution operations can be impacted by risks such as mechanical failures, supply chain issues impacting timely access to critical equipment, activities of third parties, terrorism, cyberattacks, damage to facilities, solar panels and infrastructure caused by hurricanes, storms, falling trees, lightning strikes, floods, fires and other natural disasters. Natural gas pipeline operations can also be impacted by risks such as leaks, explosions, mechanical failures, activities of third parties, terrorism, cyberattacks, and damage to the pipeline facilities and equipment caused by hurricanes, storms, floods, fires and other natural disasters. Refer to "Global Climate Change Risk" and "Weather Risk". Electric utility and natural gas transmission and distribution pipeline operation interruption could negatively affect revenue, earnings, and cash flows as well as customer and public confidence, and public safety.

Emera manages these risks by investing in a highly skilled workforce, operating prudently, preventative maintenance, safety and operations management systems, third-party risk program, and making effective capital investments. Insurance, warranties, or recovery through regulatory mechanisms may not cover any or all these losses, which could adversely affect the Company's results of operations and cash flows.

### Fuel Supply Disruptions:

Emera's electric and natural gas utilities are also exposed to the risk of fuel supply chain disruptions, both within and outside their service territories, which may be caused by severe weather or natural disasters. This may also be caused by damage to, operational issues with, terrorist or cyberattacks on, third party fuel production, storage, pipeline, and distribution facilities. The risk of fuel supply disruptions is managed through contractual protections, maintaining a diversity of fuel suppliers and transportation contracts, and contracting for access to third-party storage facilities. Significant unanticipated fuel supply disruptions could result in increased exposure to commodity price risk for Emera's regulated electric and gas utilities and Emera Energy, and these could have adverse effects on service to utility customers and on the Company's reputation, earnings, cash flow and financial position.

### UNINSURED RISK

Emera and its subsidiaries maintain insurance to cover accidental loss suffered to its facilities and to provide indemnity in the event of liability to third parties. This is consistent with Emera's risk management policies. Certain facilities, in particular coal and other thermal generation, may, over time, become more difficult (or uneconomic) to insure as a result of the impact of global climate change. Refer to "Global Climate Change Risk – Markets". There are certain elements of Emera's operations which are not insured. These include a significant portion of its electric utilities' transmission and distribution assets and its gas utilities' distribution assets, as is customary in the industry. The cost of this coverage is not economically viable. In addition, Emera accepts deductibles and self-insured retentions under its various insurance policies. Insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities or losses that may be incurred by the Company and its subsidiaries will be covered by insurance.

The occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by Emera and its subsidiaries, or claims that fall within a significant self-insured retention could have a material adverse effect on Emera's results of operations, cash flows and financial position, if regulatory recovery is not available.

The Company manages its insured risk by aligning insurance limits with risk exposures, and for uninsured assets and operations, that appropriate risk assessments and mitigation measures are in place. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including uninsured losses.

## Risk Management including Financial Instruments

Emera's risk management policies and procedures provide a framework through which management monitors various risk exposures. Risk management policies and practices are overseen by the Board. The Company has established a number of processes and practices to identify, monitor, report on and mitigate material risks to the Company. This includes establishment of the ERMC, whose responsibilities include preparing an updated risk dashboard and heat map presented at regular meetings of the Board's Risk and Sustainability Committee. Furthermore, a corporate team independent from operations is responsible for tracking and reporting on market and credit risks.

The Company manages exposure to normal operating and market risks relating to commodity prices, FX, interest rates and share prices through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of FX forwards and swaps, interest rate options and swaps, equity derivatives, and coal, oil and gas futures, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. These physical and financial contracts are classified as HFT. Collectively, these contracts and financial instruments are considered derivatives.

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

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, 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 value recognized in net income in the reporting period, unless deferred as a result of regulatory accounting.

Derivatives entered into by NSPI, NMGC and GBPC that are documented as economic hedges or for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. 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 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. TEC has no derivatives related to hedging as a result of a FPSC approved five-year moratorium on hedging of natural gas purchases that ended on December 31, 2022 and was extended through December 31, 2024 as a result of TEC's 2021 rate case settlement agreement.

Derivatives that do not meet any of the above criteria are designated as HFT, with changes in FV normally recorded in net income of the period. 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 RECOGNIZED ON THE BALANCE SHEET

| As at<br>millions of dollars | **December 31<br>2023** | December 31<br>2022 |
|---|---|---|
| *Regulatory Deferral:* | | |
| Derivative instrument assets (1) | **$ 16** | $ 238 |
| Derivative instrument liabilities (2) | **(76)** | (25) |
| Regulatory assets (1) | **88** | 30 |
| Regulatory liabilities (2) | **(17)** | (230) |
| Net asset | **$ 11** | $ 13 |
| *HFT Derivatives:* | | |
| Derivative instrument assets (1) | **$ 202** | $ 153 |
| Derivatives instruments liabilities (2) | **(421)** | (1,025) |
| Net liability | **$ (219)** | $ (872) |
| *Other Derivatives:* | | |
| Derivative instrument assets (1) | **$ 22** | $ 5 |
| Derivatives instruments liabilities (2) | **(7)** | (28) |
| Net asset (liability) | **$ 15** | $ (23) |

(1) Current and other assets.
(2) Current and long-term liabilities.

## REALIZED AND UNREALIZED GAINS (LOSSES) RECOGNIZED IN NET INCOME

| For the<br>millions of dollars | Year ended December 31<br>**2023** | <br>2022 |
|---|---|---|
| *Regulatory Deferral:* | | |
| Regulated fuel for generation and purchased power (1) | **$ 62** | $ 210 |
| *HFT Derivatives:* | | |
| Non-regulated operating revenues | **$ 1,037** | $ 64 |
| *Other Derivatives:* | | |
| OM&G | **$ (9)** | $ (22) |
| Other income, net | **17** | (24) |
| Net gains (losses) | **$ 8** | $ (46) |
| Total net gains | **$ 1,107** | $ 228 |

(1) Realized gains (losses) on derivative instruments settled and consumed in the period, hedging relationships that have been terminated or the hedged transaction is no longer probable. Realized gains (losses) recorded in inventory will be recognized in "Regulated fuel for generation and purchased power" when the hedged item is consumed.

For the year ended December 31, 2023, unrealized gains of $2 million (2022 – $2 million), have been reclassified out of AOCI into interest expense.

| As at<br>millions of dollars | **December 31,<br>2023<br>Interest rate<br>hedge** | December 31,<br>2022<br>Interest rate<br>hedge |
|---|---|---|
| Total unrealized gain in AOCI – net of tax | **$ 14** | $ 16 |

## Disclosure and Internal Controls

Management is responsible for establishing and maintaining adequate disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). The Company's internal control framework is based on criteria published in the Internal Control Integrated Framework (2013), a report issued by the Committee of Sponsoring Organizations ("COSO") of the Treadway Commission. Management, including the Chief Executive Officer and Chief Financial Officer, evaluated the design and effectiveness of the Company's DC&P and ICFR as at December 31, 2023 to provide reasonable assurance regarding the reliability of financial reporting in accordance with USGAAP.

Management recognizes the inherent limitations in internal control systems, no matter how well designed. Control systems determined to be appropriately designed can only provide reasonable assurance with respect to the reliability of financial reporting and may not prevent or detect all misstatements.

There were no changes in the Company's ICFR, during the year ended December 31, 2023, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

## Critical Accounting Estimates

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect 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 ("ARO"), 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.

### RATE REGULATION

The rate-regulated accounting policies of Emera's rate-regulated subsidiaries and regulated equity investments are subject to examination and approval by their respective regulators and may differ from the accounting policies of non-rate-regulated companies. Differences occur when regulators render their decisions on rate applications or other matters, and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on expectations of the future actions of the regulators. Assumptions and judgments used by regulatory authorities continue to have an impact on recovery of costs, rates earned on invested capital, and the timing and amount of assets to be recovered. Application of regulatory accounting guidance is a critical accounting policy as a change in these assumptions may result in a material impact on reported assets, liabilities and the results of operations.

As at December 31, 2023, the Company had recorded $3,105 million (2022 – $3,620 million) of regulatory assets and $1,772 million (2022 – $2,273 million) of regulatory liabilities.

### ACCUMULATED RESERVE – COST OF REMOVAL

TEC, PGS, NMGC and NSPI recognize non-ARO costs of removal ("COR") as regulatory liabilities. The non-ARO COR represent estimated funds received from customers through depreciation rates to cover future COR of PP&E upon retirement that are not legally required. The companies accrue for COR over the life of the related assets based on depreciation studies approved by their respective regulators. Costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays. As at December 31, 2023, the balance of the Accumulated reserve – COR within regulatory liabilities was $849 million (2022 – $895 million).

## PENSION AND OTHER POST-RETIREMENT EMPLOYEE BENEFITS

The Company provides post-retirement benefits to employees, including defined benefit pension plans. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future expectations.

The accounting related to employee post-retirement benefits is a critical accounting estimate. Changes in the estimated benefit obligation, affected by employee demographics – including age, compensation levels, employment periods, contribution levels and earnings – could have a material impact on reported assets, liabilities, accumulated other comprehensive income and results of operations. Changes in key actuarial assumptions, including anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation and benefit costs, could change annual funding requirements. This could have a significant impact on the Company's annual earnings and cash requirements.

Pension plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in changes to pension costs in future periods.

The Company's accounting policy is to amortize the net actuarial gain or loss that exceeds 10 per cent of the greater of the projected benefit obligation / accumulated post-retirement benefit obligation ("PBO") and the market-related value of assets, over active plan members' average remaining service period. For the largest plans this is currently 8.0 years (8.4 years for 2023 benefit cost) for Canadian plans and a weighted average of 11.5 years for United States plans. The Company's use of smoothed asset values reduces volatility related to amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the PBO.

The discount rate used to determine benefit costs is based on the yield of high quality long-term corporate bonds in each operating entity's country and is determined with reference to bonds which have the same duration as the PBO as at January 1 of the fiscal year. The following table shows the discount rate for benefit cost purposes and the expected return on plan assets for each plan:

| | | **2023** | | 2022 |
|---|---|---|---|---|
| | **Discount rate for benefit cost purposes** | **Expected return on plan assets** | Discount rate for benefit cost purposes | Expected return on plan assets |
| TECO Energy Group Retirement Plan | **5.55%** | **7.05%** | 2.78% | 6.50% |
| TECO Energy Group Supplemental Executive Retirement Plan [1] | **5.45%/5.31%** | **N/A** | 2.35/5.33% | N/A |
| TECO Energy Group Benefit Restoration Plan [1] | **5.48/5.30/5.49%** | **N/A** | 2.27/4.19/5.48% | N/A |
| TECO Energy Post-retirement Health and Welfare Plan | **5.53%/6.14%** | **N/A** | 2.84% | N/A |
| New Mexico Gas Company Retiree Medical Plan | **5.55%** | **2.50%** | 2.85% | 1.50% |
| NSPI | **5.17%, 5.19%** | **6.25%** | 3.25%, 3.48% | 5.75% |
| GBPC Salaried | **5.75%** | **6.00%** | 5.75% | 6.00% |
| GBPC Union | **5.75%** | **5.35%** | 5.75% | 5.35% |

(1) The discount rate for benefit cost purposes is updated throughout the year as special events occur, such as settlements and curtailments.

Based on management's estimate, the reported benefit cost for defined benefit and defined contribution plans was $43 million in 2023 (2022 – $64 million). The reported benefit cost is impacted by numerous assumptions, including the discount rate and asset return assumptions. A 0.25 per cent change in the discount rate and asset return assumptions would have had +/- impact on the 2023 benefit cost of $0.5 million and $2.5 million, respectively (2022 – $0.5 million and $1 million).

## UNBILLED REVENUE

Electric and gas revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for other Emera utilities. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and determine related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses, inter-period changes to customer classes and applicable customer rates. Based on the extent of estimates included in determination of unbilled revenue, actual results may differ from the estimate. At December 31, 2023, unbilled revenues totalled $363 million (2022 – $424 million) on total regulated operating revenues of $7,235 million (2022 – $7,154 million).

## PP&E

PP&E represents 62 per cent of total assets on the Company's balance sheet and includes generation, transmission and distribution, and other assets of the Company.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of depreciable assets in each category. The service lives of regulated PP&E are determined based on depreciation studies and require appropriate regulatory approval. Due to the magnitude of the Company's PP&E, changes in estimated depreciation rates can have a material impact on depreciation expense and accumulated depreciation.

Depreciation expense was $1,019 million for the year ended December 31, 2023 (2022 – $927 million).

## GOODWILL IMPAIRMENT ASSESSMENTS

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated FV of identifiable assets acquired, and liabilities assumed at the acquisition date.

Goodwill is subject to assessment for impairment at the reporting unit level annually, or if an event or change in circumstances indicates that the FV of a reporting unit may be below its carrying value. Application of the goodwill impairment test requires management judgment on significant assumptions and estimates. When assessing goodwill for impairment, the Company has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, management considers, among other factors, macroeconomic conditions, industry and market considerations and overall financial performance.

If the Company performs a qualitative assessment and determines it is more likely than not that its FV is less than its carrying amount, or if the Company chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test compares the FV of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its FV, an impairment loss is recorded. Significant assumptions used in estimating the FV of a reporting unit include discount and growth rates, rate case assumptions including future cost of capital, valuation of the reporting units' net operating loss ("NOL"), and projected operating and capital cash flows. Adverse changes in these assumptions could result in a future material impairment of the goodwill assigned to Emera's reporting units.

As of December 31, 2023, $5,868 million (2022 – $6,009 million) of Emera's goodwill represents the excess of the acquisition purchase price for TECO Energy (TEC, PGS and NMGC reporting units) over the FV assigned to identifiable assets acquired and liabilities assumed. In Q4 2023, qualitative assessments were performed for NMGC and PGS, given the significant excess of FV over carrying amounts calculated during the last quantitative tests in Q4 2022 and Q4 2019, respectively. Management concluded it was more likely than not that the FV of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result no impairment charges were recognized.

As of December 31, 2023, the Company had goodwill with a total carrying amount of $5,871 million (December 31, 2022 – $6,012 million). The change in the carrying value of goodwill from 2022 to 2023 was a result of the effect of the FX translation of Emera's foreign affiliates.

In Q4 2022, as a result of a quantitative assessment, the Company recorded a goodwill impairment charge of $73 million, reducing the GBPC goodwill balance to nil as at December 31, 2022. For further detail, refer to note 22 in the consolidated financial statements.

## LONG-LIVED ASSETS IMPAIRMENT ASSESSMENTS

The Company assesses whether there has been an impairment of long-lived assets and intangibles when a triggering event occurs, such as a significant market disruption or the sale of a business. The assessment involves comparing undiscounted expected future cash flows, to the carrying value of the asset. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its estimated FV.

The Company believes accounting estimates related to asset impairments are critical estimates, as they are highly susceptible to change and the impact of an impairment on reported assets and earnings could be material. Management is required to make assumptions based on expectations regarding results of operations for significant/indefinite future periods and current and expected market conditions in such periods. Markets can experience significant uncertainties. Estimates based on the Company's assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The Company's expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which consider external factors and market forces, as of the end of each reporting period. Assumptions made by management are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

As at December 31, 2023, there were no indications of impairment of Emera's long-lived assets. No impairment charges were recognized in either 2023 or 2022.

## INCOME TAXES

Income taxes are determined based on expected tax treatment of transactions recorded in the consolidated financial statements. In determining income taxes, tax legislation is interpreted in a variety of jurisdictions, the likelihood that deferred income tax assets will be recovered from future taxable income is assessed, and assumptions are made about expected timing of reversal of deferred income tax assets and liabilities. Uncertainty associated with application of tax statutes and regulations and outcomes of tax audits and appeals, requires that judgments and estimates be made in the accrual process and in calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" threshold may be recognized or continue to be recognized. Unrecognized tax benefits are evaluated quarterly and changes are recorded based on new information, including issuance of relevant guidance by the courts or tax authorities and developments occurring in examinations of the Company's tax returns.

The Company believes accounting estimates related to income taxes are critical estimates. Realization of deferred income tax assets depends on the generation of sufficient taxable income, both operating and capital, in future periods. A change in estimated valuation allowance could have a material impact on reported assets and results of operations. Administrative actions of tax authorities, changes in tax law or regulation, and uncertainty associated with the application of tax statutes and regulations, could change the Company's estimate of income taxes, including the potential for elimination or reduction of the Company's ability to realize tax benefits and to utilize deferred income tax assets.

## ASSET RETIREMENT OBLIGATIONS

Measurement of the FV of AROs requires the Company to make reasonable estimates concerning the method and timing of settlement associated with legally obligated costs. There are uncertainties in estimating future asset-retirement costs due to potential events, such as changing legislation or regulations, and advances in remediation technologies. Emera has AROs associated with remediation of generation, transmission, distribution and pipeline assets.

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

Some of the Company's transmission and distribution assets may have conditional AROs that are not recognized in the consolidated financial statements as the FV of these obligations could not be reasonably estimated given insufficient information to do so. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at FV when an amount can be determined.

As at December 31, 2023, AROs recorded on the balance sheet were $192 million (2022 – $174 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $426 million (2022 – $429 million), which will be incurred between 2023 and 2061. The majority of these costs will be incurred between 2028 and 2050.

### FINANCIAL INSTRUMENTS

The Company is required to determine the FV of all derivatives except those that qualify for the normal purchase, normal sale exception. FV is the price that would be received for the sale of an asset or paid to transfer a liability in an orderly arms-length transaction between market participants at the measurement date. FV measurements are required to reflect assumptions that market participants would use in pricing an asset or liability based on the best available information, including the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

### LEVEL DETERMINATIONS AND CLASSIFICATIONS

The Company uses Level 1, 2, and 3 classifications in the FV hierarchy. The FV measurement of a financial instrument is included in only one of the three levels and is based on the lowest level input significant to the derivation of the FV. FV is determined, directly or indirectly, using inputs that are observable for the asset or liability. Only in limited circumstances does the Company enter into commodity transactions involving non-standard features where market observable data is not available or have contract terms that extend beyond five years.

## Changes in Accounting Policies and Practices

### FUTURE ACCOUNTING PRONOUNCEMENTS

The Company considers the applicability and impact of all ASUs 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, and interim periods within annual reporting periods beginning after December 15, 2025. 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.

### 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 is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

## Summary of Quarterly Results

| For the quarter ended<br>millions of dollars<br>(except per share amounts) | **Q4 2023** | Q3 2023 | Q2 2023 | Q1 2023 | Q4 2022 | Q3 2022 | Q2 2022 | Q1 2022 |
|---|---|---|---|---|---|---|---|---|
| Operating revenues | **$ 1,972** | $ 1,740 | $ 1,418 | $ 2,433 | $ 2,358 | $ 1,835 | $ 1,380 | $ 2,015 |
| Net income (loss) attributable to common shareholders | **$ 289** | $ 101 | $ 28 | $ 560 | $ 483 | $ 167 | $ (67) | $ 362 |
| Adjusted net income | **$ 175** | $ 204 | $ 162 | $ 268 | $ 249 | $ 203 | $ 156 | $ 242 |
| EPS – basic | **$ 1.04** | $ 0.37 | $ 0.10 | $ 2.07 | $ 1.80 | $ 0.63 | $ (0.25) | $ 1.38 |
| EPS – diluted | **$ 1.04** | $ 0.37 | $ 0.10 | $ 2.07 | $ 1.80 | $ 0.63 | $ (0.25) | $ 1.38 |
| Adjusted EPS – basic | **$ 0.63** | $ 0.75 | $ 0.60 | $ 0.99 | $ 0.93 | $ 0.76 | $ 0.59 | $ 0.92 |

Quarterly operating revenues and adjusted net income are affected by seasonality. 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. Seasonal and other weather patterns, as well as the number and severity of storms, can affect demand for energy and the cost of service. Quarterly results could also be affected by items outlined in the "Significant Items Affecting Earnings" section.

# Management Report

**Management's Responsibility for Financial Reporting**

The accompanying consolidated financial statements of Emera Incorporated and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The consolidated financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles. When alternative accounting methods exist, management has chosen those it considers most appropriate in the circumstances. In preparation of these consolidated financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management represents that such estimates, which have been properly reflected in the accompanying consolidated financial statements, are based on careful judgments and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the consolidated financial statements.

Emera Incorporated maintains effective systems of internal accounting and administrative controls, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is reliable and accurate, and that Emera Incorporated's assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee is appointed by the Board, and its members are directors who are not officers or employees of Emera Incorporated. The Audit Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the consolidated financial statements and the external auditors' report. The Audit Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian Generally Accepted Auditing Standards and with the standards of the Public Company Accounting Oversight Board. Ernst & Young LLP has full and free access to the Audit Committee.

February 26, 2024

**"Scott Balfour"**
President and Chief Executive Officer

**"Gregory Blunden"**
Chief Financial Officer

# Independent Auditor's Report

To the Shareholders and the Board of Directors of Emera Incorporated

## Opinion

We have audited the consolidated financial statements of Emera Incorporated (the "Company"), which comprise the Consolidated Balance Sheets as at December 31, 2023 and 2022, and the Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2023 and 2022, and the consolidated results of its operations and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles ("USGAAP").

## Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

## Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in the audit of the consolidated financial statements of the current period. These matters were addressed in the context of the audit of the consolidated financial statements as a whole, and in forming the auditor's opinion thereon, and we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the consolidated financial statements. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying consolidated financial statements.

| | **Accounting for the effects of rate regulation** |
|---|---|
| Key Audit Matter | As disclosed in note 6 of the consolidated financial statements, the Company has $3.1 billion in regulatory assets and $1.8 billion in regulatory liabilities. The Company's rate-regulated subsidiaries are subject to regulation by various federal, state and provincial regulatory authorities in the geographic regions in which they operate. The regulatory rates are designed to recover the prudently incurred costs of providing the regulated products or services and provide a reasonable return on the equity invested or assets, as applicable. In addition to regulatory assets and liabilities, rate regulation impacts multiple financial statement line items, including, but not limited to, property, plant and equipment ("PP&E"), operating revenues and expenses, income taxes, and depreciation expense.<br><br>Auditing the impact of rate regulation on the Company's financial statements is complex and highly judgmental due to the significant judgments made by the Company to support its accounting and disclosure for regulatory matters when final regulatory decisions or orders have not yet been obtained or when regulatory formulas are complex. There is also subjectivity involved in assessing the potential impact of future regulatory decisions on the financial statements. Although the Company expects to recover costs from customers through rates, there is a risk that the regulator will not approve full recovery of the costs incurred. The Company's judgments include making an assessment of the probability of recovery of and return on costs incurred, of the potential disallowance of part of the cost incurred, or of the probable refund to customers of gains or amounts previously collected from customers through future rates. |

**Accounting for the effects of rate regulation**

| | |
|---|---|
| How Our Audit Addressed the Key Audit Matter | We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, PP&E, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries' filings for any evidence that might contradict the Company's assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery or refund in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries, gains or amounts previously collected from customers or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation. |

**Fair value ("FV") measurement of derivative financial instruments**

| | |
|---|---|
| Key Audit Matter | Held-for-trading ("HFT") derivative assets of $348 million and liabilities of $567 million, disclosed in note 15 to the consolidated financial statements, are measured at FV. The Company recognized $1,037 million in realized and unrealized gains during the year with respect to HFT derivatives.<br><br>Auditing the Company's valuation of HFT derivatives is complex and highly judgmental due to the complexity of the contract terms and valuation models, and the significant estimation required in determining the FV of the contracts. In determining the FV of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials. These assumptions have a significant impact on the FV of the HFT derivatives. |
| How Our Audit Addressed the Key Audit Matter | We performed audit procedures that included, amongst others, reviewing executed contracts and agreements for the identification of inputs and assumptions impacting the valuation of derivatives. With the support of our valuation specialists, we assessed the methodology and mathematical accuracy of the Company's valuation models and compared the commodity pricing curves used by the Company to current market and economic data. For the forward commodity pricing curves, we compared the Company's pricing curves to independently sourced pricing curves. We also assessed the methodology and mathematical accuracy of the Company's calculations to develop correlation factors and basis differentials. In addition, we assessed whether the FV hierarchy disclosures in note 16 to the consolidated financial statements were consistent with the source of the significant inputs and assumptions used in determining the FV of derivatives. |

## Other information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- The information, other than the consolidated financial statements and our auditor's reports thereon, in the Annual Report

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion & Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

The Annual Report is expected to be made available to us after the date of the auditor's report. If based on the work we will perform on this other information, we conclude there is a material misstatement of other information, we are required to report that fact to those charged with governance.

### Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with USGAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

### Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Tracy Brennan.

Ernst + Young LLP

Chartered Professional Accountants

Halifax, Canada
February 26, 2024

# Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Emera Incorporated

### Opinion on the Consolidated Financial Statements

We have audited the accompanying Consolidated Balance Sheets of Emera Incorporated (the "Company") as of December 31, 2023 and 2022, the related Consolidated Statements of Income, Consolidated Statements of Comprehensive Income, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2023 and 2022, and the consolidated results of its operations and its consolidated cash flows for each of the two years in the period ended December 31, 2023, in conformity with United States generally accepted accounting principles.

### Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

## Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

| | |
|---|---|
| | **Accounting for the effects of rate regulation** |
| Description of the Matter | As disclosed in note 6 of the consolidated financial statements, the Company has $3.1 billion in regulatory assets and $1.8 billion in regulatory liabilities. The Company's rate-regulated subsidiaries are subject to regulation by various federal, state and provincial regulatory authorities in the geographic regions in which they operate. The regulatory rates are designed to recover the prudently incurred costs of providing the regulated products or services and provide a reasonable return on the equity invested or assets, as applicable. In addition to regulatory assets and liabilities, rate regulation impacts multiple financial statement line items, including, but not limited to, PP&E, operating revenues and expenses, income taxes, and depreciation expense.<br><br>Auditing the impact of rate regulation on the Company's financial statements is complex and highly judgmental due to the significant judgments made by the Company to support its accounting and disclosure for regulatory matters when final regulatory decisions or orders have not yet been obtained or when regulatory formulas are complex. There is also subjectivity involved in assessing the potential impact of future regulatory decisions on the financial statements. Although the Company expects to recover costs from customers through rates, there is a risk that the regulator will not approve full recovery of the costs incurred. The Company's judgments include making an assessment of the probability of recovery of and return on costs incurred, of the potential disallowance of part of the cost incurred, or of the probable refund of gains or amounts previously collected from customers through future rates. |
| How We Addressed the Matter in Our Audit | We performed audit procedures that included, amongst others, assessing the Company's evaluation of the probability of future recovery for regulatory assets, PP&E, and refund of regulatory liabilities by obtaining and reviewing relevant regulatory orders, filings, testimony, hearings and correspondence, and other publicly available information. For regulatory matters for which regulatory decisions or orders have not yet been obtained, we inspected the rate-regulated subsidiaries' filings for any evidence that might contradict the Company's assertions, and reviewed other regulatory orders, filings and correspondence for other entities within the same or similar jurisdictions to assess the likelihood of recovery or refund in future rates based on the regulator's treatment of similar costs under similar circumstances. We obtained and evaluated an analysis from the Company and corroborated that analysis with letters from legal counsel, when appropriate, regarding cost recoveries, gains or amounts previously collected from customers or future changes in rates. We also assessed the methodology, accuracy and completeness of the Company's calculations of regulatory asset and liability balances based on provisions and formulas outlined in rate orders and other correspondence with the regulators. We evaluated the Company's disclosures related to the impacts of rate regulation. |

**FV measurement of derivative financial instruments**

Description of the Matter

HFT derivative assets of $348 million and liabilities of $567 million, disclosed in note 15 to the consolidated financial statements, are measured at FV. The Company recognized $1,037 million in realized and unrealized gains during the year with respect to HFT derivatives.

Auditing the Company's valuation of HFT derivatives is complex and highly judgmental due to the complexity of the contract terms and valuation models, and the significant estimation required in determining the FV of the contracts. In determining the FV of HFT derivatives, significant assumptions about future economic and market assumptions with uncertain outcomes are used, including third-party sourced forward commodity pricing curves based on illiquid markets, internally developed correlation factors and basis differentials. These assumptions have a significant impact on the FV of the HFT derivatives.

How We Addressed the Matter in Our Audit

We performed audit procedures that included, amongst others, reviewing executed contracts and agreements for the identification of inputs and assumptions impacting the valuation of derivatives. With the support of our valuation specialists, we assessed the methodology and mathematical accuracy of the Company's valuation models and compared the commodity pricing curves used by the Company to current market and economic data. For the forward commodity pricing curves, we compared the Company's pricing curves to independently sourced pricing curves. We also assessed the methodology and mathematical accuracy of the Company's calculations to develop correlation factors and basis differentials. In addition, we assessed whether the FV hierarchy disclosures in note 16 to the consolidated financial statements were consistent with the source of the significant inputs and assumptions used in determining the FV of derivatives.

Ernst & Young LLP

Chartered Professional Accountants

We have served as the Company's auditor since 1998.

Halifax, Canada
February 26, 2024

**Emera Incorporated**

# Consolidated Statements of Income

| For the<br>millions of dollars (except per share amounts) | Year ended December 31<br>**2023** | <br>2022 |
|---|---|---|
| **Operating revenues** | | |
| Regulated electric | **$ 5,746** | $ 5,473 |
| Regulated gas | **1,489** | 1,681 |
| Non-regulated | **328** | 434 |
| Total operating revenues (note 5) | **7,563** | 7,588 |
| **Operating expenses** | | |
| Regulated fuel for generation and purchased power | **1,881** | 2,171 |
| Regulated cost of natural gas | **527** | 800 |
| Operating, maintenance and general expenses ("OM&G") | **1,879** | 1,596 |
| Provincial, state, and municipal taxes | **433** | 367 |
| Depreciation and amortization | **1,049** | 952 |
| GBPC Impairment charge (note 22) | **–** | 73 |
| Total operating expenses | **5,769** | 5,959 |
| **Income from operations** | **1,794** | 1,629 |
| Income from equity investments (note 7) | **146** | 129 |
| Other income, net (note 8) | **158** | 145 |
| Interest expense, net (note 9) | **925** | 709 |
| **Income before provision for income taxes** | **1,173** | 1,194 |
| Income tax expense (note 10) | **128** | 185 |
| **Net income** | **1,045** | 1,009 |
| Non-controlling interest in subsidiaries | **1** | 1 |
| Preferred stock dividends | **66** | 63 |
| **Net income attributable to common shareholders** | **$ 978** | $ 945 |
| | | |
| Weighted average shares of common stock outstanding (in millions) (note 12) | | |
| Basic | **274** | 266 |
| Diluted | **274** | 266 |
| Earnings per common share (note 12) | | |
| Basic | **$ 3.57** | $ 3.56 |
| Diluted | **$ 3.57** | $ 3.55 |
| Dividends per common share declared | **$ 2.7875** | $ 2.6775 |

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

**Emera Incorporated**

# Consolidated Statements of Comprehensive Income

| For the<br>millions of dollars | | Year ended December 31<br>2023 | | 2022 |
|---|---|---|---|---|
| **Net income** | **$** | **1,045** | $ | 1,009 |
| **Other comprehensive (loss) income, net of tax** | | | | |
| Foreign currency translation adjustment (1) | | **(270)** | | 629 |
| Unrealized gains (losses) on net investment hedges (2) (3) | | **38** | | (97) |
| Cash flow hedges – reclassification adjustment for gains included in income (4) | | **(2)** | | (2) |
| Unrealized losses on available-for-sale investment | | **–** | | (1) |
| Net change in unrecognized pension and post-retirement benefit obligation (5) | | **(39)** | | 24 |
| Other comprehensive (loss) income (6) | | **(273)** | | 553 |
| **Comprehensive income** | | **772** | | 1,562 |
| Comprehensive income attributable to non-controlling interest | | **1** | | 1 |
| **Comprehensive Income of Emera Incorporated** | **$** | **771** | $ | 1,561 |

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

(1) Net of tax recovery of $7 million for the year ended December 31, 2023 (2022 – $7 million expense).
(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 nil for the year ended December 31, 2023 (2022 – $6 million recovery).
(4) Net of tax expense of nil for the year ended December 31, 2023 (2022 – $1 million recovery).
(5) Net of tax expense of $1 million for the year ended December 31, 2023 (2022 – $1 million expense).
(6) Net of tax recovery of $6 million for the year ended December 31, 2023 (2022 – $1 million expense).

**Emera Incorporated**

# Consolidated Balance Sheets

| As at<br>millions of dollars | | December 31<br>2023 | | December 31<br>2022 |
|---|---|---|---|---|
| **Assets** | | | | |
| **Current assets** | | | | |
| Cash and cash equivalents | **$** | **567** | $ | 310 |
| Restricted cash (note 32) | | **21** | | 22 |
| Inventory (note 14) | | **790** | | 769 |
| Derivative instruments (notes 15 and 16) | | **174** | | 296 |
| Regulatory assets (note 6) | | **339** | | 602 |
| Receivables and other current assets (note 18) | | **1,817** | | 2,897 |
| | | **3,708** | | 4,896 |
| **Property, plant and equipment ("PP&E")**, net of accumulated depreciation and amortization of $9,994 and $9,574, respectively (note 20) | | **24,376** | | 22,996 |
| **Other assets** | | | | |
| Deferred income taxes (note 10) | | **208** | | 237 |
| Derivative instruments (notes 15 and 16) | | **66** | | 100 |
| Regulatory assets (note 6) | | **2,766** | | 3,018 |
| Net investment in direct finance and sales type leases (note 19) | | **621** | | 604 |
| Investments subject to significant influence (note 7) | | **1,402** | | 1,418 |
| Goodwill (note 22) | | **5,871** | | 6,012 |
| Other long-term assets (note 32) | | **462** | | 461 |
| | | **11,396** | | 11,850 |
| **Total assets** | **$** | **39,480** | $ | 39,742 |

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

**Emera Incorporated**

# Consolidated Balance Sheets (continued)

| As at<br>millions of dollars | **December 31 2023** | December 31 2022 |
|---|---|---|
| **Liabilities and Equity** | | |
| **Current liabilities** | | |
| Short-term debt (note 23) | **$ 1,433** | $ 2,726 |
| Current portion of long-term debt (note 25) | **676** | 574 |
| Accounts payable | **1,454** | 2,025 |
| Derivative instruments (notes 15 and 16) | **386** | 888 |
| Regulatory liabilities (note 6) | **168** | 495 |
| Other current liabilities (note 24) | **427** | 579 |
| | **4,544** | 7,287 |
| **Long-term liabilities** | | |
| Long-term debt (note 25) | **17,689** | 15,744 |
| Deferred income taxes (note 10) | **2,352** | 2,196 |
| Derivative instruments (notes 15 and 16) | **118** | 190 |
| Regulatory liabilities (note 6) | **1,604** | 1,778 |
| Pension and post-retirement liabilities (note 21) | **265** | 281 |
| Other long-term liabilities (notes 7 and 26) | **820** | 825 |
| | **22,848** | 21,014 |
| **Equity** | | |
| Common stock (note 11) | **8,462** | 7,762 |
| Cumulative preferred stock (note 28) | **1,422** | 1,422 |
| Contributed surplus | **82** | 81 |
| Accumulated other comprehensive income ("AOCI") (note 13) | **305** | 578 |
| Retained earnings | **1,803** | 1,584 |
| Total Emera Incorporated equity | **12,074** | 11,427 |
| Non-controlling interest in subsidiaries (note 29) | **14** | 14 |
| Total equity | **12,088** | 11,441 |
| **Total liabilities and equity** | **$ 39,480** | $ 39,742 |

Commitments and contingencies (note 27)

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

**Approved on behalf of the Board of Directors**

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

**"Scott Balfour"**
President and Chief Executive Officer

**Emera Incorporated**

# Consolidated Statements of Cash Flows

| For the<br>millions of dollars | Year ended December 31<br>**2023** | <br>2022 |
|---|---|---|
| **Operating activities** | | |
| Net income | **$ 1,045** | $ 1,009 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | **1,060** | 959 |
| Income from equity investments, net of dividends | **(22)** | (61) |
| Allowance for funds used during construction ("AFUDC") – equity | **(38)** | (52) |
| Deferred income taxes, net | **97** | 152 |
| Net change in pension and post-retirement liabilities | **(68)** | (48) |
| NSPI Fuel adjustment mechanism ("FAM") | **(88)** | (162) |
| Net change in Fair Value ("FV") of derivative instruments | **(666)** | 206 |
| Net change in regulatory assets and liabilities | **554** | (471) |
| Net change in capitalized transportation capacity | **434** | (445) |
| GBPC impairment charge | **–** | 73 |
| Other operating activities, net | **28** | (13) |
| Changes in non-cash working capital (note 30) | **(95)** | (234) |
| **Net cash provided by operating activities** | **2,241** | 913 |
| **Investing activities** | | |
| Additions to PP&E | **(2,937)** | (2,596) |
| Other investing activities | **20** | 27 |
| **Net cash used in investing activities** | **(2,917)** | (2,569) |
| **Financing activities** | | |
| Change in short-term debt, net | **(66)** | 1,028 |
| Proceeds from short-term debt with maturities greater than 90 days | **548** | 544 |
| Repayment of short-term debt with maturities greater than 90 days | **(1,086)** | (680) |
| Proceeds from long-term debt, net of issuance costs | **1,932** | 784 |
| Retirement of long-term debt | **(151)** | (367) |
| Net (repayments) proceeds under committed credit facilities | **(96)** | 511 |
| Issuance of common stock, net of issuance costs | **424** | 277 |
| Dividends on common stock | **(488)** | (472) |
| Dividends on preferred stock | **(66)** | (63) |
| Other financing activities | **(12)** | (7) |
| **Net cash provided by financing activities** | **939** | 1,555 |
| Effect of exchange rate changes on cash, cash equivalents, and restricted cash | **(7)** | 16 |
| **Net increase (decrease) in cash, cash equivalents, and restricted cash** | **256** | (85) |
| Cash, cash equivalents, and restricted cash, beginning of year | **332** | 417 |
| Cash, cash equivalents, and restricted cash, end of year | **$ 588** | $ 332 |
| **Cash, cash equivalents, and restricted cash consists of:** | | |
| Cash | **$ 559** | $ 302 |
| Short-term investments | **8** | 8 |
| Restricted cash | **21** | 22 |
| Cash, cash equivalents, and restricted cash | **$ 588** | $ 332 |

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

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

**Emera Incorporated**

# Consolidated Statements of Changes in Equity

| millions of dollars | Common Stock | Preferred Stock | Contributed Surplus | AOCI | Retained Earnings | Non-Controlling Interest | Total Equity |
|---|---|---|---|---|---|---|---|
| Balance, December 31, 2022 | **$ 7,762** | **$ 1,422** | **$ 81** | **$ 578** | **$ 1,584** | **$ 14** | **$ 11,441** |
| Net income of Emera Inc. | **–** | **–** | **–** | **–** | **1,044** | **1** | **1,045** |
| Other comprehensive loss, net of tax recovery of $6 million | **–** | **–** | **–** | **(273)** | **–** | **–** | **(273)** |
| Dividends declared on preferred stock (note 28) | **–** | **–** | **–** | **–** | **(66)** | **–** | **(66)** |
| Dividends declared on common stock ($2.7875/share) | **–** | **–** | **–** | **–** | **(759)** | **–** | **(759)** |
| Issued under the at-the-market program ("ATM"), net of after-tax issuance costs | **397** | **–** | **–** | **–** | **–** | **–** | **397** |
| Issued under the Dividend Reinvestment Program ("DRIP"), net of discount | **272** | **–** | **–** | **–** | **–** | **–** | **272** |
| Senior management stock options exercised and Employee Common Share Purchase Plan ("ECSPP") | **31** | **–** | **1** | **–** | **–** | **–** | **32** |
| Other | **–** | **–** | **–** | **–** | **–** | **(1)** | **(1)** |
| **Balance, December 31, 2023** | **$ 8,462** | **$ 1,422** | **$ 82** | **$ 305** | **$ 1,803** | **$ 14** | **$ 12,088** |
| | | | | | | | |
| Balance, December 31, 2021 | $ 7,242 | $ 1,422 | $ 79 | $ 25 | $ 1,348 | $ 34 | $ 10,150 |
| Net income of Emera Inc. | – | – | – | – | 1,008 | 1 | 1,009 |
| Other comprehensive income, net of tax expense of $1 million | – | – | – | 553 | – | – | 553 |
| Dividends declared on preferred stock (note 28) | – | – | – | – | (63) | – | (63) |
| Dividends declared on common stock ($2.6775/share) | – | – | – | – | (709) | – | (709) |
| Issued under the ATM, net of after-tax issuance costs | 248 | – | – | – | – | – | 248 |
| Issued under the DRIP, net of discount | 238 | – | – | – | – | – | 238 |
| Senior management stock options exercised and ECSPP | 34 | – | 2 | – | – | – | 36 |
| Disposal of non-controlling interest of Dominica Electricity Services Ltd ("Domlec") | – | – | – | – | – | (20) | (20) |
| Other | – | – | – | – | – | (1) | (1) |
| Balance, December 31, 2022 | $ 7,762 | $ 1,422 | $ 81 | $ 578 | $ 1,584 | $ 14 | $ 11,441 |

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

**Emera Incorporated**

# Notes to the Consolidated Financial Statements

As at December 31, 2023 and 2022

## 1. Summary of Significant Accounting Policies

### NATURE OF OPERATIONS

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

At December 31, 2023, Emera's reportable segments include the following:

- Florida Electric Utility, which consists of Tampa Electric ("TEC"), a vertically integrated regulated electric utility, serving approximately 840,000 customers 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, serving approximately 549,000 customers; and
  - Emera Newfoundland & Labrador Holdings Inc. ("ENL"), consisting of two transmission investments related to an 824 megawatt ("MW") hydroelectric generating facility at Muskrat Falls on the Lower Churchill River in Labrador, developed by Nalcor Energy. ENL's two investments are:
    - a 100 per cent equity interest in NSP Maritime Link Inc. ("NSPML"), which developed the Maritime Link Project, a $1.8 billion transmission project, including AFUDC; and
    - a 31 per cent equity interest in the partnership capital of Labrador-Island Link Limited Partnership ("LIL"), a $3.7 billion electricity transmission project in Newfoundland and Labrador.
- Gas Utilities and Infrastructure, which includes:
  - Peoples Gas System Inc. ("PGS"), a regulated gas distribution utility, serving approximately 490,000 customers across Florida. Effective January 1, 2023, Peoples Gas System ceased to be a division of Tampa Electric Company and the gas utility was reorganized, resulting in a separate legal entity called Peoples Gas System Inc., a wholly owned direct subsidiary of TECO Gas Operations, Inc.;
  - New Mexico Gas Company, Inc. ("NMGC"), a regulated gas distribution utility, serving approximately 540,000 customers in New Mexico;
  - 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, serving approximately 134,000 customers;
  - Grand Bahama Power Company Limited ("GBPC"), a vertically integrated regulated electric utility on Grand Bahama Island, serving approximately 19,000 customers; 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 reportable segment includes investments in energy-related non-regulated companies which include:
  - 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") and TECO Finance, Inc. ("TECO Finance"), financing subsidiaries of Emera;
  - Block Energy LLC (previously Emera Technologies 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 consolidated financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP") and in the opinion of management, include all adjustments that are of a recurring nature and necessary to fairly state the financial position of Emera.

All dollar amounts are presented in Canadian dollars ("CAD"), unless otherwise indicated.

## PRINCIPLES OF CONSOLIDATION

These consolidated financial statements include the accounts of Emera Incorporated, its majority-owned subsidiaries, and a variable interest entity ("VIE") in which Emera is the primary beneficiary. Emera uses the equity method of accounting to record investments in which the Company has the ability to exercise significant influence, and for VIEs in which Emera is not the primary beneficiary.

The Company performs ongoing analysis to assess whether it holds any VIEs or whether any reconsideration events have arisen with respect to existing VIEs. To identify potential VIEs, management reviews contractual and ownership arrangements such as leases, long-term purchase power agreements, tolling contracts, guarantees, jointly owned facilities and equity investments. VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the VIE that most significantly impacts its economic performance and the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. In circumstances where Emera has an investment in a VIE but is not deemed the primary beneficiary, the VIE is accounted for using the equity method. For further details on VIEs, refer to note 32.

Intercompany balances and transactions have been eliminated on consolidation, except for the net profit on certain transactions between certain non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The net profit on these transactions, which would be eliminated in the absence of the accounting standards for rate-regulated entities, is recorded in non-regulated operating revenues. An offset is recorded to PP&E, regulatory assets, regulated fuel for generation and purchased power, or OM&G, depending on the nature of the transaction.

## USE OF MANAGEMENT ESTIMATES

The preparation of consolidated financial statements in accordance with USGAAP requires management to make estimates and assumptions. These may affect 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 ("ARO"), 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.

## REGULATORY MATTERS

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third-party regulator. Rates are designed to recover prudently incurred costs of providing regulated products or services and provide an opportunity for a reasonable rate of return on invested capital, as applicable. For further detail, refer to note 6.

## FOREIGN CURRENCY TRANSLATION

Monetary assets and liabilities denominated in foreign currencies are converted to CAD at the rates of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date are included in income.

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

The Company designates certain USD denominated debt held in CAD functional currency companies as hedges of net investments in USD denominated foreign operations. The change in the carrying amount of these investments, measured at exchange rates in effect at the balance sheet date is recorded in Other Comprehensive Income ("OCI").

## REVENUE RECOGNITION

### Regulated Electric and Gas Revenue:

Electric and gas revenues, including energy charges, demand charges, basic facilities charges and clauses and riders, are recognized when obligations under the terms of a contract are satisfied, which is when electricity and gas are delivered to customers over time as the customer simultaneously receives and consumes the benefits. Electric and gas revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity and gas are recognized at rates approved by the respective regulators and recorded based on metered usage, which occurs on a periodic, systematic basis, generally monthly or bi-monthly. At the end of each reporting period, electricity and gas delivered to customers, but not billed, is estimated and corresponding unbilled revenue is recognized. The Company's estimate of unbilled revenue at the end of the reporting period is calculated by estimating the megawatt hours ("MWh") or therms delivered to customers at the established rates expected to prevail in the upcoming billing cycle. This estimate includes assumptions as to the pattern of energy demand, weather, line losses and inter-period changes to customer classes.

### Non-regulated Revenue:

Marketing and trading margins are comprised of Emera Energy's corresponding purchases and sales of natural gas and electricity, pipeline capacity costs and energy asset management revenues. Revenues are recorded when obligations under terms of the contract are satisfied and are presented on a net basis reflecting the nature of contractual relationships with customers and suppliers.

Energy sales are recognized when obligations under the terms of the contracts are satisfied, which is when electricity is delivered to customers over time.

Other non-regulated revenues are recorded when obligations under the terms of the contract are satisfied.

### Other:

Sales, value add, and other taxes, except for gross receipts taxes discussed below, collected by the Company concurrent with revenue-producing activities are excluded from revenue.

## FRANCHISE FEES AND GROSS RECEIPTS

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

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

## PP&E

PP&E is recorded at original cost, including AFUDC or capitalized interest, net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units, are included in "PP&E" on the Consolidated Balance Sheets. When units of regulated PP&E are replaced, renewed or retired, their cost, plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation, with no gain or loss reflected in income. Where a disposition of non-regulated PP&E occurs, gains and losses are included in income as the dispositions occur.

The cost of PP&E represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property or interest for non-regulated property, ARO, and overhead attributable to the capital project. Overhead includes corporate costs such as finance, information technology and labour costs, along with other costs related to support functions, employee benefits, insurance, procurement, and fleet operating and maintenance. Expenditures for project development are capitalized if they are expected to have a future economic benefit.

Normal maintenance projects and major maintenance projects that do not increase overall life of the related assets are expensed as incurred. When a major maintenance project increases the life or value of the underlying asset, the cost is capitalized.

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

Intangible assets, which are included in "PP&E" on the Consolidated Balance Sheets, consist primarily of computer software and land rights. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the asset in each category. For some of Emera's rate-regulated subsidiaries, amortization is calculated using the amortizable life method which is applied to the net book value to date over the remaining life of those assets. The service lives of regulated intangible assets require regulatory approval.

## GOODWILL

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated FV of identifiable assets acquired and liabilities assumed at the acquisition date. Goodwill is carried at initial cost less any write-down for impairment and is adjusted for the impact of foreign exchange ("FX"). Goodwill is subject to assessment for impairment at the reporting unit level annually, or if an event or change in circumstances indicates that the FV of a reporting unit may be below its carrying value. When assessing goodwill for impairment, the Company has the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment management considers, among other factors, macroeconomic conditions, industry and market considerations and overall financial performance.

If the Company performs a qualitative assessment and determines it is more likely than not that its FV is less than its carrying amount, or if the Company chooses to bypass the qualitative assessment, a quantitative test is performed. The quantitative test compares the FV of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its FV, an impairment loss is recorded. Management estimates the FV of the reporting unit by using the income approach, or a combination of the income and market approach. The income approach uses a discounted cash flow analysis which relies on management's best estimate of the reporting unit's projected cash flows. The analysis includes an estimate of terminal values based on these expected cash flows using a methodology which derives a valuation using an assumed perpetual annuity based on the reporting unit's residual cash flows. The discount rate used is a market participant rate based on a peer group of publicly traded comparable companies and represents the weighted average cost of capital of comparable companies. For the market approach, management estimates FV based on comparable companies and transactions within the utility industry. Significant assumptions used in estimating the FV of a reporting unit using an income approach include discount and growth rates, rate case assumptions including future cost of capital, valuation of the reporting unit's net operating loss ("NOL") and projected operating and capital cash flows. Adverse changes in these assumptions could result in a future material impairment of the goodwill assigned to Emera's reporting units.

As of December 31, 2023, $5,868 million of Emera's goodwill represents the excess of the acquisition purchase price for TECO Energy (TEC, PGS and NMGC reporting units) over the FV assigned to identifiable assets acquired and liabilities assumed. In Q4 2023, qualitative assessments were performed for NMGC and PGS given the significant excess of FV over carrying amounts calculated during the last quantitative tests in Q4 2022 and Q4 2019, respectively. Management concluded it was more likely than not that the FV of these reporting units exceeded their respective carrying amounts, including goodwill. As such, no quantitative testing was required. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result, no impairment charges were recognized.

In Q4 2022, as a result of a quantitative assessment, the Company recorded a goodwill impairment charge of $73 million, reducing the GBPC goodwill balance to nil as at December 31, 2022. For further details, refer to note 22.

## INCOME TAXES AND INVESTMENT TAX CREDITS

Emera recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the Consolidated Balance Sheets, and their respective tax bases using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period when the change is enacted, unless required to be offset to a regulatory asset or liability by law or by order of the regulator. Emera recognizes the effect of income tax positions only when it is more likely than not that they will be realized. Management reviews all readily available current and historical information, including forward-looking information, and the likelihood that deferred income tax assets will be recovered from future taxable income is assessed and assumptions are made about the expected timing of reversal of deferred income tax assets and liabilities. If management subsequently determines it is likely that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded to reflect the amount of deferred income tax asset expected to be realized.

Generally, investment tax credits are recorded as a reduction to income tax expense in the current or future periods to the extent that realization of such benefit is more likely than not. Investment tax credits earned on regulated assets by TEC, PGS and NMGC are deferred and amortized as required by regulatory practices.

TEC, PGS, NMGC and BLPC collect income taxes from customers based on current and deferred income taxes. NSPI, ENL and Brunswick Pipeline collect income taxes from customers based on income tax that is currently payable, except for the deferred income taxes on certain regulatory balances specifically prescribed by regulators. For the balance of regulated deferred income taxes, NSPI, ENL and Brunswick Pipeline recognize regulatory assets or liabilities where the deferred income taxes are expected to be recovered from or returned to customers in future years. These regulated assets or liabilities are grossed up using the respective income tax rate to reflect the income tax associated with future revenues that are required to fund these deferred income tax liabilities, and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets. GBPC is not subject to income taxes.

Emera classifies interest and penalties associated with unrecognized tax benefits as interest and operating expense, respectively. For further detail, refer to note 10.

## DERIVATIVES AND HEDGING ACTIVITIES

The Company manages its exposure to normal operating and market risks relating to commodity prices, FX, interest rates and share prices through contractual protections with counterparties where practicable, and by using financial instruments consisting mainly of FX forwards and swaps, interest rate options and swaps, equity derivatives, and coal, oil and gas futures, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. These physical and financial contracts are classified as HFT. Collectively, these contracts and financial instruments are considered derivatives.

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

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and can be proven to effectively hedge identified risk both at the inception and over the term of the instrument. Specifically, for cash flow hedges, 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.

Derivatives entered into by NSPI, NMGC and GBPC that are documented as economic hedges or for which the NPNS exception has not been taken, are subject to regulatory accounting treatment. 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 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. TEC has no derivatives related to hedging as a result of a FPSC approved five-year moratorium on hedging of natural gas purchases that ended on December 31, 2022 and was extended through December 31, 2024 as a result of TEC's 2021 rate case settlement agreement.

Derivatives that do not meet any of the above criteria are designated as HFT, with changes in FV normally recorded in net income of the period. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

Emera classifies gains and losses on derivatives as a component of non-regulated operating revenues, fuel for generation and purchased power, other expenses, inventory, and OM&G, depending on the nature of the item being economically hedged. Transportation capacity arising as a result of marketing and trading derivative transactions is recognized as an asset in "Receivables and other current assets" and amortized over the period of the transportation contract term. Cash flows from derivative activities are presented in the same category as the item being hedged within operating or investing activities on the Consolidated Statements of Cash Flows. Non-hedged derivatives are included in operating cash flows on the Consolidated Statements of Cash Flows.

Derivatives, as reflected on the Consolidated Balance Sheets, are not offset by the FV amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in "Receivables and other current assets" and obligations to return cash collateral are recognized in "Accounts payable".

## LEASES

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

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

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

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

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

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

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

## CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash equivalents consist of highly liquid short-term investments with original maturities of three months or less at acquisition.

## RECEIVABLES AND ALLOWANCE FOR CREDIT LOSSES

Utility customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity and gas sales are approximately 30 days. A late payment fee may be assessed on account balances after the due date. The Company recognizes allowances for credit losses to reduce accounts receivable for amounts expected to be uncollectable. Management estimates credit losses related to accounts receivable by considering historical loss experience, customer deposits, current events, the characteristics of existing accounts and reasonable and supportable forecasts that affect the collectability of the reported amount. Provisions for credit losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

## INVENTORY

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

## ASSET IMPAIRMENT

### Long-Lived Assets:

Emera assesses whether there has been an impairment of long-lived assets and intangibles when a triggering event occurs, such as a significant market disruption or sale of a business.

The assessment involves comparing undiscounted expected future cash flows to the carrying value of the asset. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its estimated FV. The Company's assumptions relating to future results of operations or other recoverable amounts, are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The Company's expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which consider external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

As at December 31, 2023, there are no indications of impairment of Emera's long-lived assets. No impairment charges related to long-lived assets were recognized in 2023 or 2022.

### Equity Method Investments:

The carrying value of investments accounted for under the equity method are assessed for impairment by comparing the FV of these investments to their carrying values, if a FV assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists, and it is determined to be other-than-temporary, a charge is recognized in earnings equal to the amount the carrying value exceeds the investment's FV. No impairment of equity method investments was required in either 2023 or 2022.

**Financial Assets:**

Equity investments, other than those accounted for under the equity method, are measured at FV, with changes in FV recognized in the Consolidated Statements of Income. Equity investments that do not have readily determinable FV are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investments. No impairment of financial assets was required in either 2023 or 2022.

## ASSET RETIREMENT OBLIGATIONS

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

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

Some of the Company's transmission and distribution assets may have conditional AROs that are not recognized in the consolidated financial statements, as the FV of these obligations could not be reasonably estimated, given insufficient information to do so. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at FV in the period in which an amount can be determined.

## COST OF REMOVAL ("COR")

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

## STOCK-BASED COMPENSATION

The Company has several stock-based compensation plans: a common share option plan for senior management; an employee common share purchase plan; a deferred share unit ("DSU") plan; a performance share unit ("PSU") plan; and a restricted share unit ("RSU") plan. The Company accounts for its plans in accordance with the FV-based method of accounting for stock-based compensation. Stock-based compensation cost is measured at the grant date, based on the calculated FV of the award, and is recognized as an expense over the employee's or director's requisite service period using the graded vesting method. Stock-based compensation plans recognized as liabilities are initially measured at FV and re-measured at FV at each reporting date, with the change in liability recognized in income

## EMPLOYEE BENEFITS

The costs of the Company's pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes unamortized gains and losses and past service costs in "AOCI" or "Regulatory assets" on the Consolidated Balance Sheets. The components of net periodic benefit cost other than the service cost component are included in "Other income, net" on the Consolidated Statements of Income. For further detail, refer to note 21.

## 2. Future Accounting Pronouncements

The Company considers the applicability and impact of all ASUs 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, and interim periods within annual reporting periods beginning after December 15, 2025. 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.

### 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 is currently evaluating the impact of adoption of the standard on its consolidated financial statements.

## 3. Dispositions

On March 31, 2022, Emera completed the sale of its 51.9 per cent interest in Domlec for proceeds which approximated its carrying value. Domlec was included in the Company's Other Electric reportable segment up to its date of sale. The sale did not have a material impact on earnings.

## 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 year ended December 31, 2023** | | | | | | | |
| Operating revenues from external customers (1) | $ 3,548 | $ 1,671 | $ 1,510 | $ 526 | $ 308 | $ – | **$ 7,563** |
| Inter-segment revenues (1) | 8 | – | 14 | – | 31 | (53) | **–** |
| Total operating revenues | 3,556 | 1,671 | 1,524 | 526 | 339 | (53) | **7,563** |
| Regulated fuel for generation and purchased power | 920 | 699 | – | 275 | – | (13) | **1,881** |
| Regulated cost of natural gas | – | – | 527 | – | – | – | **527** |
| OM&G | 830 | 384 | 405 | 130 | 151 | (21) | **1,879** |
| Provincial, state and municipal taxes | 289 | 45 | 91 | 3 | 5 | – | **433** |
| Depreciation and amortization | 571 | 276 | 126 | 68 | 8 | – | **1,049** |
| Income from equity investments | – | 109 | 21 | 4 | 12 | – | **146** |
| Other income, net | 69 | 32 | 11 | 7 | 20 | 19 | **158** |
| Interest expense, net (2) | 271 | 170 | 129 | 23 | 332 | – | **925** |
| Income tax expense (recovery) | 117 | (9) | 64 | – | (44) | – | **128** |
| Non-controlling interest in subsidiaries | – | – | – | 1 | – | – | **1** |
| Preferred stock dividends | – | – | – | – | 66 | – | **66** |
| Net income (loss) attributable to common shareholders | $ 627 | $ 247 | $ 214 | $ 37 | $ (147) | $ – | **$ 978** |
| Capital expenditures | $ 1,736 | $ 450 | $ 664 | $ 63 | $ 8 | $ – | **$ 2,921** |
| **As at December 31, 2023** | | | | | | | |
| Total assets | $ 21,119 | $ 8,634 | $ 7,735 | $ 1,311 | $ 1,938 | $ (1,257) | **$39,480** |
| Investments subject to significant influence | $ – | $ 1,236 | $ 118 | $ 48 | $ – | $ – | **$ 1,402** |
| Goodwill | $ 4,628 | $ – | $ 1,240 | $ – | $ 3 | $ – | **$ 5,871** |

(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 and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.

(2) Segment net income is reported on a basis that includes internally allocated financing costs of $95 million for the year ended December 31, 2023, between the Florida Electric Utility, 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 year ended December 31, 2022** | | | | | | | |
| Operating revenues from external customers (1) | $ 3,280 | $ 1,675 | $ 1,697 | $ 518 | $ 418 | $ – | **$ 7,588** |
| Inter-segment revenues (1) | 7 | – | 7 | – | 22 | (36) | **-** |
| Total operating revenues | 3,287 | 1,675 | 1,704 | 518 | 440 | (36) | **7,588** |
| Regulated fuel for generation and purchased power | 1,086 | 803 | – | 290 | – | (8) | **2,171** |
| Regulated cost of natural gas | – | – | 800 | – | – | – | **800** |
| OM&G | 625 | 338 | 365 | 123 | 156 | (11) | **1,596** |
| Provincial, state and municipal taxes | 235 | 43 | 83 | 3 | 3 | – | **367** |
| Depreciation and amortization | 507 | 259 | 118 | 61 | 7 | – | **952** |
| Income from equity investments | – | 87 | 21 | 4 | 17 | – | **129** |
| Other income (expenses), net | 68 | 24 | 13 | – | 23 | 17 | **145** |
| Interest expense, net (2) | 185 | 136 | 81 | 19 | 288 | – | **709** |
| GBPC impairment charge | – | – | – | 73 | – | – | **73** |
| Income tax expense (recovery) | 121 | (8) | 70 | – | 2 | – | **185** |
| Non-controlling interest in subsidiaries | – | – | – | 1 | – | – | **1** |
| Preferred stock dividends | – | – | – | – | 63 | – | **63** |
| Net income (loss) attributable to common shareholders | $ 596 | $ 215 | $ 221 | $ (48) | $ (39) | $ – | **$ 945** |
| Capital expenditures | $ 1,425 | $ 507 | $ 574 | $ 63 | $ 6 | $ – | **$ 2,575** |
| **As at December 31, 2022** | | | | | | | |
| Total assets | $ 21,053 | $ 8,223 | $ 7,737 | $ 1,337 | $ 2,835 | $ (1,443) | **$ 39,742** |
| Investments subject to significant influence | $ – | $ 1,241 | $ 128 | $ 49 | $ – | $ – | **$ 1,418** |
| Goodwill | $ 4,739 | $ – | $ 1,270 | $ – | $ 3 | $ – | **$ 6,012** |

(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 and agreed to by the related parties. Eliminated transactions are included in determining reportable segments.

(2) Segment net income is reported on a basis that includes internally allocated financing costs of $13 million for the year ended December 31, 2022, between the Gas Utilities and Infrastructure and Other segments.

## GEOGRAPHICAL INFORMATION

Revenues (based on country of origin of the product or service sold)

| For the<br>millions of dollars | Year ended December 31<br>**2023** | <br>2022 |
|---|---|---|
| United States | **$ 5,310** | $ 5,346 |
| Canada | **1,727** | 1,725 |
| Barbados | **389** | 384 |
| The Bahamas | **137** | 122 |
| Dominica | **–** | 11 |
| | **$ 7,563** | $ 7,588 |

Property Plant and Equipment:

| As at<br>millions of dollars | **December 31<br>2023** | December 31<br>2022 |
|---|---|---|
| United States | **$ 18,588** | $ 17,382 |
| Canada | **4,878** | 4,689 |
| Barbados | **576** | 583 |
| The Bahamas | **334** | 342 |
| | **$ 24,376** | $ 22,996 |

# 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 year ended December 31, 2023** | | | | | | | |
| **Regulated Revenue** | | | | | | | |
| Residential | $ 2,307 | $ 910 | $ 183 | $ 724 | $ – | $ – | $ 4,124 |
| Commercial | 1,083 | 463 | 285 | 425 | – | – | 2,256 |
| Industrial | 274 | 219 | 33 | 93 | – | (13) | 606 |
| Other electric | 395 | 41 | 7 | – | – | – | 443 |
| Regulatory deferrals | (522) | – | 12 | – | – | – | (510) |
| Other (1) | 19 | 38 | 6 | 199 | – | (8) | 254 |
| Finance income (2) (3) | – | – | – | 62 | – | | 62 |
| Regulated revenue | $ 3,556 | $ 1,671 | $ 526 | $ 1,503 | $ – | $ (21) | $ 7,235 |
| **Non-Regulated Revenue** | | | | | | | |
| Marketing and trading margin (4) | – | – | – | – | 96 | – | 96 |
| Other non-regulated operating revenue | – | – | – | 21 | 27 | (23) | 25 |
| Mark-to-market (3) | – | – | – | – | 216 | (9) | 207 |
| Non-regulated revenue | $ – | $ – | $ – | $ 21 | $ 339 | $ (32) | $ 328 |
| **Total operating revenues** | **$ 3,556** | **$ 1,671** | **$ 526** | **$ 1,524** | **$ 339** | **$ (53)** | **$ 7,563** |
| **For the year ended December 31, 2022** | | | | | | | |
| **Regulated Revenue** | | | | | | | |
| Residential | $ 1,799 | $ 834 | $ 184 | $ 800 | $ – | $ – | $ 3,617 |
| Commercial | 869 | 427 | 282 | 461 | – | – | 2,039 |
| Industrial | 230 | 353 | 32 | 83 | – | (7) | 691 |
| Other electric | 398 | 28 | 6 | – | – | – | 432 |
| Regulatory deferrals | (27) | – | 6 | – | – | – | (21) |
| Other (1) | 18 | 33 | 8 | 283 | – | (7) | 335 |
| Finance income (2) (3) | – | – | – | 61 | – | – | 61 |
| Regulated revenue | $ 3,287 | $ 1,675 | $ 518 | $ 1,688 | $ – | $ (14) | $ 7,154 |
| **Non-Regulated** | | | | | | | |
| Marketing and trading margin (4) | – | – | – | – | 143 | – | 143 |
| Other non-regulated operating revenue | – | – | – | 16 | 16 | (10) | 22 |
| Mark-to-market (3) | – | – | – | – | 281 | (12) | 269 |
| Non-regulated revenue | $ – | $ – | $ – | $ 16 | $ 440 | $ (22) | $ 434 |
| **Total operating revenues** | $ 3,287 | $ 1,675 | $ 518 | $ 1,704 | $ 440 | $ (36) | $ 7,588 |

(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 December 31, 2023, the aggregate amount of the transaction price allocated to remaining performance obligations was $488 million (2022 – $450 million). This amount includes $134 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 2043.

# 6. Regulatory Assets and Liabilities

Regulatory assets represent prudently incurred costs that have been deferred because it is probable they will be recovered through future rates or tolls collected from customers. Management believes existing regulatory assets are probable for recovery either because the Company received specific approval from the applicable regulator, or due to regulatory precedent established for similar circumstances. If management no longer considers it probable that an asset will be recovered, deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

For regulatory assets and liabilities that are amortized, the amortization is as approved by the respective regulator.

| As at<br>millions of dollars | **December 31<br>2023** | December 31<br>2022 |
|---|---|---|
| **Regulatory assets** | | |
| Deferred income tax regulatory assets | **$ 1,233** | $ 1,166 |
| TEC capital cost recovery for early retired assets | **671** | 674 |
| NSPI FAM | **395** | 307 |
| Pension and post-retirement medical plan | **364** | 369 |
| Cost recovery clauses | **151** | 707 |
| Deferrals related to derivative instruments | **88** | 30 |
| Storm cost recovery clauses | **52** | 138 |
| Environmental remediations | **26** | 27 |
| Stranded cost recovery | **25** | 27 |
| NMGC winter event gas cost recovery | **-** | 69 |
| Other | **100** | 106 |
| | **$ 3,105** | $ 3,620 |
| Current | **$ 339** | $ 602 |
| Long-term | **2,766** | 3,018 |
| Total regulatory assets | **$ 3,105** | $ 3,620 |
| **Regulatory liabilities** | | |
| Accumulated reserve - COR | **849** | 895 |
| Deferred income tax regulatory liabilities | **830** | 877 |
| Cost recovery clauses | **32** | 70 |
| BLPC Self-insurance fund ("SIF") (note 32) | **29** | 30 |
| Deferrals related to derivative instruments | **17** | 230 |
| NMGC gas hedge settlements (note 18) | **-** | 162 |
| Other | **15** | 9 |
| | **$ 1,772** | $ 2,273 |
| Current | **$ 168** | $ 495 |
| Long-term | **1,604** | 1,778 |
| Total regulatory liabilities | **$ 1,772** | $ 2,273 |

### Deferred Income Tax Regulatory Assets and Liabilities

To the extent deferred income taxes are expected to be recovered from or returned to customers in future years, a regulatory asset or liability is recognized as appropriate.

### TEC Capital Cost Recovery for Early Retired Assets

This regulatory asset is related to the remaining net book value of Big Bend Power Station Units 1 through 3 and smart meter assets that were retired. The balance earns a rate of return as permitted by the FPSC and is recovered as a separate line item on customer bills for a period of 15 years. This recovery mechanism is authorized by and survives the term of the settlement agreement approved by the FPSC in 2021. For further information, refer to "Big Bend Modernization Project" in the TEC section below.

### NSPI FAM

NSPI has a FAM, approved by the UARB, allowing NSPI to recover fluctuating fuel and certain fuel-related costs from customers through regularly scheduled fuel rate adjustments. Differences between prudently incurred fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in subsequent periods.

### Pension and Post-Retirement Medical Plan

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

### Cost Recovery Clauses

These assets and liabilities are related to TEC, PGS and NMGC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC or New Mexico Public Regulation Commission ("NMPRC"), as applicable, on a dollar-for-dollar basis in a subsequent period.

### Deferrals Related to Derivative Instruments

This asset is primarily related to NSPI deferring changes in FV of derivatives that are documented as economic hedges or that do not qualify for NPNS exemption, as a regulatory asset or liability as approved by the UARB. The realized gain or loss is recognized when the hedged item settles in regulated fuel for generation and purchased power, other income, inventory, or OM&G, depending on the nature of the item being economically hedged.

### Storm Cost Recovery Clauses

#### TEC and PGS Storm Reserve:

The storm reserve is for hurricanes and other named storms that cause significant damage to TEC and PGS systems. As allowed by the FPSC, if charges to the storm reserve exceed the storm liability, the excess is to be carried as a regulatory asset. TEC and PGS can petition the FPSC to seek recovery of restoration costs over a 12-month period or longer, as determined by the FPSC, as well as replenish the reserve. In 2022, TEC and PGS were impacted by Hurricane Ian. For further information, refer to "TEC Storm Reserve" in the Florida Electric Utility section below.

#### NSPI Storm Rider:

NSPI has a UARB approved storm rider for each of 2023, 2024 and 2025, which gives NSPI the option to apply to the UARB for recovery of costs if major storm restoration expenses exceed approximately $10 million in a given year.

#### GBPC Storm Restoration:

This asset represents storm restoration costs incurred by GBPC. GBPC maintains insurance for its generation facilities and, as with most utilities, its transmission and distribution networks are not covered by commercial insurance.

In January 2020, the Grand Bahama Port Authority ("GBPA") approved recovery of $15 million USD of 2019 costs related to Hurricane Dorian, over a five-year period from 2021 through 2025.

Restoration costs associated with Hurricane Matthew in 2016 are being recovered through an approved fuel charge. For further information, refer to "Storm Restoration Costs – Hurricane Matthew" in the GBPC section below.

### Environmental Remediations

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

### Stranded Cost Recovery

Due to decommissioning of a GBPC steam turbine in 2012, the GBPA approved recovery of a $21 million USD stranded cost through electricity rates; it is included in rate base and expected to be included in rates in future years.

### NMGC Winter Event Gas Cost Recovery

In February 2021, the State of New Mexico experienced an extreme cold weather event that resulted in an incremental $108 million USD for gas costs above what it would normally have paid during this period. NMGC normally recovers gas supply and related costs through a purchased gas adjustment clause ("PGAC"). On June 15, 2021, the NMPRC approved recovery of $108 million USD and related borrowing costs in customer rates over a period of 30 months from July 1, 2021, to December 31, 2023.

### Accumulated Reserve – COR

This regulatory liability represents the non-ARO COR reserve in TEC, PGS, NMGC and NSPI. AROs represent the FV of estimated cash flows associated with the Company's legal obligation to retire its PP&E. Non-ARO COR represent estimated funds received from customers through depreciation rates to cover future COR of PP&E value upon retirement that are not legally required. This reduces rate base for ratemaking purposes. This liability is reduced as COR are incurred and increased as depreciation is recorded for existing assets and as new assets are put into service.

### NMGC Gas Hedge Settlements

This regulatory liability represents regulatory deferral of gas options exercised above strike price but settled subsequent to the period end. The value from cash settlement of these options flows to customers via the PGAC.

### Other Regulatory Assets and Liabilities

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

## REGULATORY ENVIRONMENTS AND UPDATES

### Florida Electric Utility

TEC is regulated by the FPSC and is also subject to regulation by the Federal Energy Regulatory Commission. The FPSC sets rates at a level that allows utilities such as TEC to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital. Base rates are determined in FPSC rate setting hearings which can occur at the initiative of TEC, the FPSC or other interested parties.

TEC's approved regulated return on equity ("ROE") range for 2023 and 2022 was 9.25 per cent to 11.25 per cent based on an allowed equity capital structure of 54 per cent. An ROE of 10.20 per cent (2022 – 10.20 per cent) is used for the calculation of the return on investments for clauses.

#### Base Rates:

On February 1, 2024, TEC notified the FPSC of its intent to seek a base rate increase effective January 2025, reflecting a revenue requirement increase of approximately $290 to $320 million USD and additional adjustments of approximately $100 million USD and $70 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 numerous other resiliency and reliability projects. The filing range amounts are estimates until TEC files its detailed case in April 2024. The FPSC is scheduled to hear the case in Q3 2024.

On August 16, 2023, TEC filed a petition to implement the 2024 Generation Base Rate Adjustment provisions pursuant to the 2021 rate case settlement agreement. Inclusive of TEC's ROE adjustment, the increase of $22 million USD was approved by the FPSC on November 17, 2023.

### Fuel Recovery and Other Cost Recovery Clauses:

TEC has a fuel recovery clause approved by the FPSC, allowing the opportunity to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. The FPSC annually approves cost-recovery rates for purchased power, capacity, environmental and conservation costs, including a return on capital invested. Differences between prudently incurred fuel costs and the cost-recovery rates and amounts recovered from customers through electricity rates in a year are deferred to a regulatory asset or liability and recovered from or returned to customers in subsequent periods.

On January 23, 2023, TEC requested an adjustment to its fuel charges to recover the 2022 fuel under-recovery of $518 million USD over a period of 21 months. The request also included an adjustment to 2023 projected fuel costs to reflect the reduction in natural gas prices since September 2022 for a projected reduction of $170 million USD for the balance of 2023. The changes were approved by the FPSC on March 7, 2023, and were effective beginning on April 1, 2023.

The mid-course fuel adjustment requested by TEC on January 19, 2022, was approved on March 1, 2022. The rate increase, effective with the first billing cycle in April 2022, covered higher fuel and capacity costs of $169 million USD, and was spread over customer bills from April 1, 2022 through December 2022.

### Big Bend Modernization Project:

TEC invested $876 million USD, including $91 million USD of AFUDC, between 2018 and 2022 to modernize the Big Bend Power Station. The modernization project repowered Big Bend Unit 1 with natural gas combined-cycle technology and eliminated coal as this unit's fuel. As part of the modernization project, TEC in 2020 retired the Unit 1 components that would not be used in the modernized plant and did the same for Big Bend Unit 2 in 2021. TEC retired Big Bend Unit 3 in 2023 as it was in the best interests of the customers from an economic, environmental risk and operational perspective. On December 31, 2021, the remaining costs of the retired Big Bend coal generation assets, Units 1 through 3, of $636 million USD and $267 million USD in accumulated depreciation were reclassified to a regulatory asset on the balance sheet.

TEC's 2021 settlement agreement provides for cost recovery of the Big Bend Modernization project in two phases. The first phase was a revenue increase to cover the costs of the assets in service during 2022, among other items. The remainder of the project costs were recovered as part of the 2023 subsequent year adjustment. The settlement agreement also includes a new charge to recover the remaining costs of the retired Big Bend coal generation assets, Units 1 through 3, which are spread over 15 years, effective January 1, 2022. This recovery mechanism was authorized by and survives the term of the settlement agreement approved by the FPSC in 2021.

### Storm Reserve:

In September 2022, TEC was impacted by Hurricane Ian, with $119 million USD of restoration costs charged against TEC's FPSC approved storm reserve. Total restoration costs charged to the storm reserve exceeded the reserve balance and have been deferred as a regulatory asset for future recovery.

On January 23, 2023, TEC petitioned the FPSC for recovery of the storm reserve regulatory asset and the replenishment of the balance in the storm reserve to the approved storm reserve level of $56 million USD, for a total of $131 million USD. The storm cost recovery surcharge was approved by the FPSC on March 7, 2023, and TEC began applying the surcharge in April 2023. Subsequently, on November 9, 2023, the FPSC approved TEC's petition, filed on August 16, 2023, to update the total storm cost collection to $134 million USD. It also changed the collection of the expected remaining balance of $29 million USD as of December 31, 2023, from over the first three months of 2024 to over the 12 months of 2024. The storm recovery is subject to review of the underlying costs for prudency and accuracy by the FPSC.

In Q3 2023, TEC was impacted by Hurricane Idalia. The related storm restoration costs were approximately $35 million USD, which were charged to the storm reserve regulatory asset, resulting in minimal impact to earnings.

### Storm Protection Cost Recovery Clause and Settlement Agreement:

The Storm Protection Plan ("SPP") Cost Recovery Clause provides a process for Florida investor-owned utilities, including TEC, to recover transmission and distribution storm hardening costs for incremental activities not already included in base rates. Differences between prudently incurred clause-recoverable costs and amounts recovered from customers through electricity rates in a year are deferred and recovered from or returned to customers in a subsequent year. A settlement agreement was approved on August 10, 2020, and TEC's cost recovery began in January 2021. The current approved plan addressed the years 2023, 2024 and 2025 and was approved by the FPSC on October 4, 2022.

## Canadian Electric Utilities

### NSPI

NSPI is a public utility as defined in the Public Utilities Act of Nova Scotia ("Public Utilities Act") and is subject to regulation under the Public Utilities Act by the UARB. The Public Utilities Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings held from time to time at NSPI's or the UARB's request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers and provide a reasonable return to investors. NSPI's approved regulated ROE range for 2023 and 2022 was 8.75 per cent to 9.25 per cent based on an actual five quarter average regulated common equity component of up to 40 per cent of approved rate base.

*General Rate Application ("GRA"):*

On February 2, 2023, the UARB approved the GRA settlement agreement between NSPI, key customer representatives and participating interest groups. This resulted in average customer rate increases of 6.9 per cent effective on February 2, 2023, and further average increases of 6.5 per cent on January 1, 2024, with any under or over-recovery of fuel costs addressed through the UARB's established FAM process. It also established a storm rider and a demand-side management rider. On March 27, 2023, the UARB issued a final order approving the electricity rates effective on February 2, 2023.

*Fuel Recovery:*

For the period of 2020 through 2022, NSPI operated under a three-year fuel stability plan with no fuel rate adjustments related to the under-recovery of fuel and fuel-related costs in the period.

On January 29, 2024, NSPI applied to the UARB for approval of a structure that would begin to recover the outstanding FAM balance. As part of the application, NSPI requested approval for the sale of $117 million of the FAM regulatory asset to Invest Nova Scotia, a provincial Crown corporation, with the proceeds paid to NSPI upon approval. NSPI has requested approval to collect from customers the amortization and financing costs of $117 million on behalf of Invest Nova Scotia over a 10-year period, and remit those amounts to Invest Nova Scotia as collected, reducing short-term customer rate increases relative to the currently established FAM process. If approved, this portion of the FAM regulatory asset would be removed from the Consolidated Balance Sheets and NSPI would collect the balance on behalf of Invest Nova Scotia in NSPI rates beginning in 2024.

*Storm Rider:*

The storm rider was effective as of the GRA decision date. The application for deferral and recovery of the storm rider is made in the year following the year of the incurred cost, with recovery beginning in the year after the application. Total major storm restoration expense for 2023 was $31 million, of which $21 million was deferred to the storm rider.

*Hurricane Fiona:*

On October 31, 2023, NSPI submitted an application to the UARB to defer $24 million in incremental operating costs incurred during Hurricane Fiona storm restoration efforts in September 2022. NSPI is seeking amortization of the costs over a period to be approved by the UARB during a future rate setting process. At December 31, 2023, the $24 million is deferred to "Other long-term assets", pending UARB approval.

*Maritime Link:*

The Maritime Link is a $1.8 billion (including AFUDC) transmission project including two 170-kilometre sub-sea cables, connecting the island of Newfoundland and Nova Scotia. The Maritime Link entered service on January 15, 2018 and NSPI started interim assessment payments to NSPML at that time.

Any difference between the amounts recovered from customers through rates and those approved by the UARB through the NSPML interim assessment application will be addressed through the FAM.

*Nova Scotia Cap-and-Trade ("Cap-and-Trade") Program:*

As of December 31, 2022, the FAM included a cumulative $166 million in fuel costs related to the accrued purchase of emissions credits and $6 million related to credits purchased from provincial auctions. On March 16, 2023, the Province of Nova Scotia provided NSPI with emissions allowances sufficient to achieve compliance for the 2019 through 2022 period. As such, compliance costs accrued of $166 million were reversed in Q1 2023. The credits NSPI purchased from provincial auctions in the amount of $6 million were not refunded and no further costs were incurred to achieve compliance with the Cap-and-Trade Program.

*Extra Large Industrial Active Demand Tariff:*

On July 5, 2023, NSPI received approval from the UARB to change the methodology in which fuel cost recovery from an industrial customer is calculated. Due to significant volatility in commodity prices in 2022, the previous methodology did not result in a reasonable determination of the fuel cost to serve this customer. The change in methodology, effective January 1, 2022, results in a shifting of fuel costs from this industrial customer to the FAM. This adjustment was recorded in Q2 2023 resulting in a $51 million increase to the FAM regulatory asset and an offsetting decrease to unbilled revenue within Receivables and other current assets. This adjustment had minimal impact on earnings.

### NSPML

Equity earnings from the Maritime Link are dependent on the approved ROE and operational performance of NSPML. NSPML's approved regulated ROE range is 8.75 per cent to 9.25 per cent, based on an actual five-quarter average regulated common equity component of up to 30 per cent.

Nalcor's Nova Scotia Block ("NS Block") delivery obligations commenced on August 15, 2021 and delivery will continue over the next 35 years pursuant to the agreements.

In February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion less $9 million of costs ($7 million after-tax) that would not have otherwise been recoverable if incurred by NSPI.

On October 4, 2023 and January 31, 2024, the UARB issued decisions providing clarification on remaining aspects of the Maritime Link holdback mechanism primarily relating to release of past and future holdback amounts and requirements to end the holdback mechanism. In these decisions, the UARB agreed with the Company's submission that $12 million ($8 million related to 2022 and $4 million relating to 2023) of the previously recorded holdback remain credited to NSPI's FAM, with the remainder released to NSPML and recorded in Emera's "Income from equity investments. NSPML did not record any additional holdback in Q4 2023. The UARB also confirmed that the holdback mechanism will cease once 90 per cent of NS Block deliveries are achieved for 12 consecutive months (subject to potential relief for planned outages or exceptional circumstances) and the net outstanding balance of previously underdelivered NS Block energy is less than 10 per cent of the contracted annual amount. In addition, the UARB increased the monthly holdback amount from $2 million to $4 million beginning December 1, 2023.

On December 21, 2023, NSPML received approval to collect up to $164 million (2023 – $164 million) from NSPI for the recovery of costs associated with the Maritime Link in 2024; subject to a holdback of up to $4 million a month, as discussed above.

## Gas Utilities and Infrastructure

### PGS

PGS is regulated by the FPSC. The FPSC sets rates at a level that allows utilities such as PGS to collect total revenues or revenue requirements equal to their cost of providing service, plus an appropriate return on invested capital.

PGS's approved ROE range for 2023 and 2022 was 8.9 per cent to 11.0 per cent with a 9.9 per cent midpoint, based on an allowed equity capital structure of 54.7 per cent.

*Base Rates:*

On April 4, 2023, PGS filed a rate case with the FPSC and a hearing for the matter was held in September 2023. On November 9, 2023, the FPSC approved a $118 million USD increase to base revenues which includes $11 million USD transferred from the cast iron and bare steel replacement rider, for a net incremental increase to base revenues of $107 million USD. This reflects a 10.15 per cent midpoint ROE with an allowed equity capital structure of 54.7 per cent. A final order was issued on December 27, 2023, with the new rates effective January 2024.

The 2020 PGS rate case settlement provided the ability to reverse a total of $34 million USD of accumulated depreciation through 2023. PGS reversed $20 million USD of accumulated depreciation in 2023 and $14 million USD in 2022.

*Fuel Recovery:*

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through its PGAC. This clause is designed to recover actual costs incurred by PGS for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers. These charges may be adjusted monthly based on a cap approved annually by the FPSC.

*Recovery of Energy Conservation and Pipeline Replacement Programs:*

The FPSC annually approves a conservation charge that is intended to permit PGS to recover prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are required by Florida law and approved and monitored by the FPSC. PGS also has a Cast Iron/Bare Steel Pipe Replacement clause to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. In February 2017, the FPSC approved expansion of the Cast Iron/Bare Steel clause to allow recovery of accelerated replacement of certain obsolete plastic pipe. The majority of cast iron and bare steel pipe has been removed from its system, with replacement of obsolete plastic pipe continuing until 2028 under the rider.

### NMGC

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

NMGC's approved ROE for 2023 and 2022 was 9.375 per cent on an allowed equity capital structure of 52 per cent.

*Base Rates:*

On September 14, 2023, NMGC filed a rate case with the NMPRC for new base rates to become effective Q4 2024. NMGC requested $49 million USD in annual base revenues primarily as a result of increased operating costs and capital investments in pipeline projects and related infrastructure. The rate case includes a requested ROE of 10.5 per cent.

*Fuel Recovery:*

NMGC recovers gas supply costs through a PGAC. This clause recovers actual costs for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, transmission, distribution, and sale of natural gas to its customers. On a monthly basis, NMGC can adjust charges based on the next month's expected cost of gas and any prior month under-recovery or over-recovery. The NMPRC requires that NMGC annually file a reconciliation of the PGAC period costs and recoveries. NMGC must file a PGAC Continuation Filing with the NMPRC every four years to establish that the continued use of the PGAC is reasonable and necessary. NMGC received approval of its PGAC Continuation in December 2020, for the four-year period ending December 2024.

*Integrity Management Programs ("IMP") Regulatory Asset:*

A portion of NMGC's annual spending on infrastructure is for IMP, or the replacement and update of legacy systems. These programs are driven both by NMGC integrity management plans and federal and state mandates. In December 2020, NMGC received approval through its rate case to defer costs through an IMP regulatory asset for certain of its IMP capital investments occurring between January 1, 2022 and December 31, 2023 and petitioned recovery of the regulatory asset in its rate case filed on December 13, 2021. On November 30, 2022, the NMPRC issued a Final Order that included approval of recovery of the IMP regulatory asset.

### Brunswick Pipeline

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Saint John LNG import terminal near Saint John, New Brunswick to markets in the northeastern United States. Brunswick Pipeline entered into a 25-year firm service agreement commencing in July 2009 with Repsol Energy North America Canada Partnership. The agreement provides for a predetermined toll increase in the fifth and fifteenth year of the contract. The pipeline is considered a Group II pipeline regulated by the Canada Energy Regulator ("CER"). The CER Gas Transportation Tariff is filed by Brunswick Pipeline in compliance with the requirements of the CER Act and sets forth the terms and conditions of the transportation rendered by Brunswick Pipeline.

## Other Electric Utilities

### BLPC

BLPC is regulated by the Fair Trading Commission ("FTC"), under the Utilities Regulation (Procedural) Rules 2003. BLPC is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on capital invested. BLPC's approved regulated return on rate base was 10 per cent for 2023 and 2022.

*Licenses:*

BLPC currently operates pursuant to a single integrated license to generate, transmit and distribute electricity on the island of Barbados until 2028. In 2019, the Government of Barbados passed legislation requiring multiple licenses for the supply of electricity. In 2021, BLPC reached commercial agreement with the Government of Barbados for each of the license types, subject to the passage of implementing legislation. The timing of the final enactment is unknown at this time, but BLPC will work towards the implementation of the licenses once enacted.

*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 related to the self-insurance fund of $50 million USD, prior year benefits recognized on remeasurement of deferred income taxes of $5 million USD, and accumulated depreciation of $16 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.

***Fuel Recovery:***

BLPC's fuel costs flow through a fuel pass-through mechanism which provides opportunity to recover all prudently incurred fuel costs from customers in a timely manner. The calculation of the fuel charge is adjusted on a monthly basis and reported to the FTC for approval.

***Clean Energy Transition Program ("CETP"):***

On May 31, 2023, the FTC approved BLPC's application to establish an alternative cost recovery mechanism to recover prudently incurred costs associated with its CETP (the "Decision"). The mechanism is intended to facilitate the timely recovery between rate cases of costs associated with approved renewable energy assets. BLPC will be required to submit an individual application for the recovery of costs of each asset through the cost recovery mechanism, meeting the minimum criteria as set out in the Decision. On October 5, 2023, BLPC applied to the FTC to recover the costs of a battery storage system through the CETP.

***Fuel Hedging:***

On October 21, 2021, the FTC approved BLPC's application to implement a fuel hedging program which will be incorporated into the calculation of the fuel clause adjustment. On November 10, 2021, BLPC requested the FTC review the required 50/50 cost sharing arrangement between BLPC and customers in relation to the hedging administrative costs, or any gains and losses associated with the hedging program.

### GBPC

GBPC is regulated by the GBPA. The GBPA has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit and distribute electricity on the island until 2054. Rates are set to recover prudently incurred costs of providing electricity service to customers plus an appropriate return on rate base. GBPC's approved regulated return on rate base was 8.32 per cent for 2023 (2022 – 8.23 per cent).

***Base Rates:***

There is a fuel pass-through mechanism and tariff review policy with new rates submitted every three years. On January 14, 2022, the GBPA issued its decision on GBPC's application for rate review that was filed with the GBPA on September 23, 2021. The decision, which became effective April 1, 2022, allows for an increase in revenues of $3.5 million USD. The rates include a regulatory ROE of 12.84 per cent.

***Fuel Recovery:***

GBPC's fuel costs flow through a fuel pass-through mechanism which provides the opportunity to recover all prudently incurred fuel costs from customers in a timely manner.

Effective November 1, 2022, GBPC's fuel pass through charge was increased due to an increase in global oil prices impacting the unhedged fuel cost. In 2023, the fuel pass through charge was adjusted monthly, in-line with actual fuel costs.

***Storm Restoration Costs – Hurricane Matthew:***

As part of the recovery of costs incurred as a result of Hurricane Matthew, in 2016, the GBPA approved a fixed per kWh fuel charge and allowed the difference between this and the actual cost of fuel to be applied to the Hurricane Matthew regulatory asset. As part of its decision on GBPC's application for rate review, issued January 14, 2022, and effective April 1, 2022, the GBPA approved the continued amortization of the remaining regulatory asset over the three year period ending December 31, 2024.

# 7. Investments Subject to Significant Influence and Equity Income

| millions of dollars | Carrying Value As at December 31 2023 | 2022 | Equity Income For the year ended December 31 2023 | 2022 | Percentage of Ownership 2023 |
|---|---|---|---|---|---|
| LIL (1) | **$ 747** | $ 740 | **$ 63** | $ 58 | **31.0** |
| NSPML | **489** | 501 | **46** | 29 | **100.0** |
| M&NP (2) | **118** | 128 | **21** | 21 | **12.9** |
| Lucelec (2) | **48** | 49 | **4** | 4 | **19.5** |
| Bear Swamp (3) | **–** | – | **12** | 17 | **50.0** |
| | **$ 1,402** | $ 1,418 | **$ 146** | $ 129 | |

(1) Emera indirectly owns 100 per cent of the Class B units, which comprises 24.5 per cent of the total units issued. Percentage ownership in LIL is subject to change, based on the balance of capital investments required from Emera and Nalcor Energy to complete construction of the LIL. Emera's ultimate percentage investment in LIL will be determined upon final costing of all transmission projects related to the Muskrat Falls development, including the LIL, Labrador Transmission Assets and Maritime Link Projects, such that Emera's total investment in the Maritime Link and LIL will equal 49 per cent of the cost of all of these transmission developments.
(2) 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.
(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 $81 million (2022 – $95 million) is recorded in Other long-term liabilities on the Consolidated Balance Sheets.

Equity investments include a $10 million difference between the cost and the underlying FV of the investees' assets as at the date of acquisition. The excess is attributable to goodwill.

Emera accounts for its variable interest investment in NSPML as an equity investment (note 32). NSPML's consolidated summarized balance sheets are illustrated as follows:

| As at millions of dollars | December 31 2023 | December 31 2022 |
|---|---|---|
| **Balance Sheets** | | |
| Current assets | **$ 21** | $ 17 |
| PP&E | **1,473** | 1,517 |
| Regulatory assets | **272** | 265 |
| Non-current assets | **29** | 29 |
| Total assets | **$ 1,795** | $ 1,828 |
| Current liabilities | **$ 48** | $ 48 |
| Long-term debt (1) | **1,109** | 1,149 |
| Non-current liabilities | **149** | 130 |
| Equity | **489** | 501 |
| Total liabilities and equity | **$ 1,795** | $ 1,828 |

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

# 8. Other Income, Net

| For the millions of dollars | Year ended December 31 2023 | 2022 |
|---|---|---|
| Interest income | **$ 43** | $ 25 |
| AFUDC | **38** | 52 |
| Pension non-current service cost recovery | **35** | 24 |
| FX gains (losses) | **20** | (26) |
| TECO Guatemala Holdings award (1) | **–** | 63 |
| Other | **22** | 7 |
| | **$ 158** | $ 145 |

(1) On December 15, 2022, a payment of $63 million was made by the Republic of Guatemala to TECO Energy in satisfaction of the second and final award issued by the International Centre of the Settlement of Investment Disputes tribunal regarding a dispute over an investment in TGH, a wholly-owned subsidiary of TECO Energy.

# 9. Interest Expense, Net

Interest expense, net consisted of the following:

| For the millions of Canadian dollars | | Year ended December 31 2023 | | 2022 |
|---|---|---|---|---|
| Interest on debt | $ | 954 | $ | 727 |
| Allowance for borrowed funds used during construction | | (16) | | (21) |
| Other | | (13) | | 3 |
| | $ | 925 | $ | 709 |

# 10. Income Taxes

The income tax provision, for the years ended December 31, differs from that computed using the enacted combined Canadian federal and provincial statutory income tax rate for the following reasons:

| millions of dollars | | 2023 | | 2022 |
|---|---|---|---|---|
| Income before provision for income taxes | $ | 1,173 | $ | 1,194 |
| Statutory income tax rate | | 29.0% | | 29.0% |
| Income taxes, at statutory income tax rate | | 340 | | 346 |
| Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities | | (72) | | (70) |
| Tax credits | | (53) | | (18) |
| Foreign tax rate variance | | (36) | | (44) |
| Amortization of deferred income tax regulatory liabilities | | (33) | | (33) |
| Tax effect of equity earnings | | (15) | | (10) |
| GBPC impairment charge | | – | | 21 |
| Other | | (3) | | (7) |
| Income tax expense | $ | 128 | $ | 185 |
| Effective income tax rate | | 11% | | 15% |

On August 16, 2022, the United States Inflation Reduction Act ("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 December 31, 2023, the Company has recorded a $30 million (2022 – $9 million) regulatory liability on the Consolidated Balance Sheets in recognition of its obligation to pass the incremental tax benefits realized to customers.

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

| millions of dollars | | 2023 | | 2022 |
|---|---|---|---|---|
| Current income taxes | | | | |
| Canada | $ | 26 | $ | 25 |
| United States | | 5 | | 8 |
| Deferred income taxes | | | | |
| Canada | | 93 | | 122 |
| United States | | 128 | | 252 |
| Investment tax credits | | | | |
| United States | | (29) | | (7) |
| Operating loss carryforwards | | | | |
| Canada | | (93) | | (94) |
| United States | | (2) | | (121) |
| Income tax expense | $ | 128 | $ | 185 |

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

| millions of dollars | | **2023** | | 2022 |
|---|---|---|---|---|
| Canada | **$** | **171** | $ | 173 |
| United States | | **964** | | 1,063 |
| Other | | **38** | | (42) |
| Income before provision for income taxes | **$** | **1,173** | $ | 1,194 |

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

| millions of dollars | | **2023** | | 2022 |
|---|---|---|---|---|
| **Deferred income tax assets:** | | | | |
| Tax loss carryforwards | **$** | **1,195** | $ | 1,207 |
| Tax credit carryforwards | | **454** | | 415 |
| Derivative instruments | | **205** | | 45 |
| Regulatory liabilities | | **175** | | 264 |
| Other | | **372** | | 341 |
| Total deferred income tax assets before valuation allowance | | **2,401** | | 2,272 |
| Valuation allowance | | **(363)** | | (312) |
| Total deferred income tax assets after valuation allowance | **$** | **2,038** | $ | 1,960 |
| **Deferred income tax (liabilities):** | | | | |
| PP&E | **$** | **(3,223)** | $ | (2,981) |
| Derivative instruments | | **(235)** | | (125) |
| Investments subject to significant influence | | **(216)** | | (181) |
| Regulatory assets | | **(196)** | | (310) |
| Other | | **(312)** | | (322) |
| Total deferred income tax liabilities | **$** | **(4,182)** | $ | (3,919) |
| **Consolidated Balance Sheets presentation:** | | | | |
| Long-term deferred income tax assets | **$** | **208** | $ | 237 |
| Long-term deferred income tax liabilities | | **(2,352)** | | (2,196) |
| Net deferred income tax liabilities | **$** | **(2,144)** | $ | (1,959) |

Considering all evidence regarding the utilization of the Company's deferred income tax assets, it has been determined that Emera is more likely than not to realize all recorded deferred income tax assets, except for certain loss carryforwards and unrealized capital losses on long-term debt and investments. A valuation allowance of $363 million has been recorded as at December 31, 2023 (2022 – $312 million) related to the loss carryforwards, long-term debt and investments.

The Company intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, as at December 31, 2023, $4.7 billion (2022 – $3.8 billion) in cumulative temporary differences for which deferred taxes might otherwise be required, have not been recognized. It is impractical to estimate the amount of income and withholding tax that might be payable if a reversal of temporary differences occurred.

Emera's NOL, capital loss and tax credit carryforwards and their expiration periods as at December 31, 2023 consisted of the following:

| millions of dollars | Tax Carryforwards | Subject to Valuation Allowance | Net Tax Carryforwards | Expiration Period |
|---|---|---|---|---|
| Canada | | | | |
| NOL | $ 2,914 | $ (1,164) | $ 1,750 | 2026-2043 |
| Capital loss | 73 | (73) | – | Indefinite |
| United States | | | | |
| Federal NOL | $ 1,360 | $ (1) | $ 1,359 | 2036-Indefinite |
| State NOL | 1,003 | (1) | 1,002 | 2026-Indefinite |
| Tax credit | 454 | (3) | 451 | 2025-2043 |
| Other | | | | |
| NOL | $ 81 | $ (28) | $ 53 | 2024-2030 |

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

| millions of dollars | **2023** | 2022 |
|---|---|---|
| Balance, January 1 | **$ 33** | $ 28 |
| Increases due to tax positions related to current year | **5** | 5 |
| Increases due to tax positions related to a prior year | **1** | 2 |
| Decreases due to tax positions related to a prior year | **(2)** | (2) |
| Balance, December 31 | **$ 37** | $ 33 |

Unrecognized tax benefits relate to the timing of certain tax deductions at NSPI and research and development tax credits primarily at TEC. The total amount of unrecognized tax benefits as at December 31, 2023 was $37 million (2022 – $33 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $9 million (2022 – $7 million) with $2 million interest expense recognized in the Consolidated Statements of Income (2022 – $1 million). No penalties have been accrued. The balance of unrecognized tax benefits could change in the next 12 months as a result of resolving Canada Revenue Agency ("CRA") and Internal Revenue Service audits. A reasonable estimate of any change cannot be made at this time.

During 2022, the CRA issued notices of reassessment to NSPI for the 2013 through 2016 taxation years. NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for its 2006 through 2010 and 2013 through 2016 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is $126 million (2022 – $126 million), including interest. NSPI has prepaid $55 million of the amount in dispute, as required by CRA.

On November 29, 2019, NSPI filed a Notice of Appeal with the Tax Court of Canada with respect to its dispute of the 2006 through 2010 taxation years. Should NSPI be successful in defending its position, all payments including applicable interest will be refunded. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the difference, if any, either owed to, or refunded from, the CRA. The related tax deductions will be available in subsequent years.

Should NSPI be similarly reassessed by the CRA for years not currently in dispute, further payments will be required; however, the ultimate permissibility of these deductions would be similarly not in dispute.

NSPI and its advisors believe that NSPI has reported its tax position appropriately. NSPI continues to assess its options to resolving the dispute; however, the outcome of the Notice of Appeal process is not determinable at this time.

Emera files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. Emera's subsidiaries file Canadian, US, Barbados, and St. Lucia income tax returns. As at December 31, 2023, the Company's tax years still open to examination by taxing authorities include 2005 and subsequent years.

# 11. Common Stock

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

| Issued and outstanding: | 2023 millions of shares | 2023 millions of dollars | 2022 millions of shares | 2022 millions of dollars |
|---|---|---|---|---|
| Balance, January 1 | **269.95** | **$ 7,762** | 261.07 | $ 7,242 |
| Issuance of common stock under ATM program (1) (2) | **8.29** | **397** | 4.07 | 248 |
| Issued under the DRIP, net of discounts | **5.26** | **272** | 4.21 | 238 |
| Senior management stock options exercised and Employee Share Purchase Plan | **0.62** | **31** | 0.60 | 34 |
| Balance, December 31 | **284.12** | **$ 8,462** | 269.95 | $ 7,762 |

(1) For the year ended December 31, 2022, a total of 4,072,469 common shares were issued under Emera's ATM program at an average price of $61.31 per share for gross proceeds of $250 million ($248 million net of after-tax issuance costs).
(2) For the year ended December 31, 2023, a total of 8,287,037 common shares were issued under Emera's ATM program at an average price of $48.27 per share for gross proceeds of $400 million ($397 million net of after-tax issuance costs).

As at December 31, 2023, the following common shares were reserved for issuance: 6 million (2022 – 6 million) under the senior management stock option plan, 2 million (2022 – 2.7 million) under the employee common share purchase plan and 18 million (2022 – 10 million) under the DRIP.

The issuance of common shares under the common share compensation arrangements does not allow the plans to exceed 10 per cent of Emera's outstanding common shares. As at December 31, 2023, Emera was in compliance with this requirement.

### ATM EQUITY PROGRAM

On October 3, 2023, Emera filed a short form base shelf prospectus, primarily in support of the renewal of its ATM Program in Q4 2023 that will allow the Company to issue up to $600 million of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price. This ATM Program is expected to remain in effect until November 4, 2025.

# 12. Earnings Per Share

Basic earnings per share is determined by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include Company contributions to the senior management stock option plan, convertible debentures and shares issued under the DRIP.

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

| For the<br>millions of dollars (except per share amounts) | Year ended December 31<br>**2023** | 2022 |
|---|---|---|
| **Numerator** | | |
| Net income attributable to common shareholders | **$ 977.7** | $ 945.1 |
| **Diluted numerator** | **977.7** | 945.1 |
| **Denominator** | | |
| Weighted average shares of common stock outstanding – basic | **273.6** | 265.5 |
| Stock-based compensation | **0.2** | 0.4 |
| **Weighted average shares of common stock outstanding – diluted** | **273.8** | 265.9 |
| **Earnings per common share** | | |
| Basic | **$ 3.57** | $ 3.56 |
| Diluted | **$ 3.57** | $ 3.55 |

## 13. Accumulated Other Comprehensive Income

The components of AOCI are as follows:

| millions of dollars | Unrealized (loss) gain on translation of self-sustaining foreign operations | Net change in net investment hedges | Losses on derivatives recognized as cash flow hedges | Net change on available-for-sale investments | Net change in unrecognized pension and post-retirement benefit costs | Total AOCI |
|---|---|---|---|---|---|---|
| **For the year ended December 31, 2023** | | | | | | |
| Balance, January 1, 2023 | **$ 639** | **$ (62)** | **$ 16** | **$ (2)** | **$ (13)** | **$ 578** |
| Other comprehensive (loss) income before reclassifications | **(270)** | **38** | **–** | **–** | **–** | **(232)** |
| Amounts reclassified from AOCI | **–** | **–** | **(2)** | **–** | **(39)** | **(41)** |
| Net current period other comprehensive (loss) income | **(270)** | **38** | **(2)** | **–** | **(39)** | **(273)** |
| **Balance, December 31, 2023** | **$ 369** | **$ (24)** | **$ 14** | **$ (2)** | **$ (52)** | **$ 305** |
| For the year ended December 31, 2022 | | | | | | |
| Balance, January 1, 2022 | $ 10 | $ 35 | $ 18 | $ (1) | $ (37) | $ 25 |
| Other comprehensive income (loss) before reclassifications | 629 | (97) | – | (1) | – | 531 |
| Amounts reclassified from AOCI | – | – | (2) | – | 24 | 22 |
| Net current period other comprehensive income (loss) | 629 | (97) | (2) | (1) | 24 | 553 |
| Balance, December 31, 2022 | $ 639 | $ (62) | $ 16 | $ (2) | $ (13) | $ 578 |

The reclassifications out of AOCI are as follows:

| For the millions of dollars | Affected line item in the Consolidated Financial Statements | Year ended December 31 **2023** | 2022 |
|---|---|---|---|
| **Gains on derivatives recognized as cash flow hedges** | | | |
| Interest rate hedge | Interest expense, net | **$ (2)** | $ (2) |
| **Net change in unrecognized pension and post-retirement benefit costs** | | | |
| Actuarial losses | Other income, net | **$ –** | $ 10 |
| Past service costs | Other income, net | **2** | – |
| Amounts reclassified into obligations | Pension and post-retirement benefits | **(40)** | 15 |
| Total before tax | | **(38)** | 25 |
| Income tax expense | | **(1)** | (1) |
| Total net of tax | | **$ (39)** | $ 24 |
| **Total reclassifications out of AOCI, net of tax, for the period** | | **$ (41)** | $ 22 |

## 14. Inventory

| As at millions of dollars | **December 31 2023** | December 31 2022 |
|---|---|---|
| Fuel | **$ 382** | $ 404 |
| Materials | **408** | 365 |
| Total | **$ 790** | $ 769 |

# 15. Derivative Instruments

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

| As at<br>millions of dollars | Derivative Assets<br>**December 31 2023** | <br>December 31 2022 | Derivative Liabilities<br>**December 31 2023** | <br>December 31 2022 |
|---|---|---|---|---|
| *Regulatory deferral:* | | | | |
| Commodity swaps and forwards | **$ 16** | $ 186 | **$ 76** | $ 42 |
| FX forwards | **3** | 18 | **3** | 1 |
| Physical natural gas purchases and sales | **–** | 52 | **–** | – |
| | **19** | 256 | **79** | 43 |
| *HFT derivatives:* | | | | |
| Power swaps and physical contracts | **29** | 89 | **36** | 77 |
| Natural gas swaps, futures, forwards, physical contracts | **319** | 340 | **531** | 1,224 |
| | **348** | 429 | **567** | 1,301 |
| *Other derivatives:* | | | | |
| Equity derivatives | **4** | – | **–** | 5 |
| FX forwards | **18** | 5 | **7** | 23 |
| | **22** | 5 | **7** | 28 |
| Total gross current derivatives | **389** | 690 | **653** | 1,372 |
| *Impact of master netting agreements:* | | | | |
| Regulatory deferral | **(3)** | (18) | **(3)** | (18) |
| HFT derivatives | **(146)** | (276) | **(146)** | (276) |
| Total impact of master netting agreements | **(149)** | (294) | **(149)** | (294) |
| **Total derivatives** | **$ 240** | $ 396 | **$ 504** | $ 1,078 |
| Current (1) | **174** | 296 | **386** | 888 |
| Long-term (1) | **66** | 100 | **118** | 190 |
| **Total derivatives** | **$ 240** | $ 396 | **$ 504** | $ 1,078 |

(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.

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

| For the<br>millions of dollars | Year ended December 31<br>**2023**<br>**Interest rate hedge** | <br>2022<br>Interest rate hedge |
|---|---|---|
| Realized gain in interest expense, net | **$ 2** | $ 2 |
| Total gains in net income | **$ 2** | $ 2 |

| As at<br>millions of dollars | **December 31 2023**<br>**Interest rate hedge** | December 31 2022<br>Interest rate hedge |
|---|---|---|
| Total unrealized gain in AOCI – effective portion, net of tax | **$ 14** | $ 16 |

The Company expects $2 million of unrealized gains currently in AOCI to be reclassified into net income within the next 12 months.

## REGULATORY DEFERRAL

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

| millions of dollars | **Physical natural gas purchases** | **Commodity swaps and forwards** | **FX forwards** | Physical natural gas purchases | Commodity swaps and forwards | FX forwards |
|---|---|---|---|---|---|---|
| For the year ended December 31 | | | **2023** | | | 2022 |
| Unrealized gain (loss) in regulatory assets | **$ –** | **$ (109)** | **$ (3)** | $ – | $ (69) | $ 1 |
| Unrealized gain (loss) in regulatory liabilities | **(3)** | **(73)** | **–** | 28 | 343 | 16 |
| Realized (gain) loss in regulatory assets | **–** | **(5)** | **–** | – | 48 | – |
| Realized (gain) loss in regulatory liabilities | **–** | **2** | **–** | – | (41) | – |
| Realized (gain) loss in inventory (1) | **–** | **4** | **(10)** | – | (121) | 1 |
| Realized (gain) in regulated fuel for generation and purchased power (2) | **(49)** | **(9)** | **(4)** | (64) | (146) | – |
| Other | **–** | **(14)** | **–** | – | – | – |
| Total change derivative instruments | **$ (52)** | **$ (204)** | **$ (17)** | $ (36) | $ 14 | $ 18 |

(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 December 31, 2023, 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) | 7 | 6 |
| *Commodity swaps and forwards purchases:* | | |
| Natural gas (Mmbtu) | 16 | 10 |
| Power (MWh) | 1 | 1 |
| Coal (metric tonnes) | 1 | – |
| *FX swaps and forwards:* | | |
| FX contracts (millions of USD) | $ 241 | $ 70 |
| Weighted average rate | 1.3155 | 1.3197 |
| % of USD requirements | 63% | 17% |

## HFT DERIVATIVES

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

| For the millions of dollars | Year ended December 31 **2023** | 2022 |
|---|---|---|
| Power swaps and physical contracts in non-regulated operating revenues | **$ (6)** | $ 17 |
| Natural gas swaps, forwards, futures and physical contracts in non-regulated operating revenues | **1,043** | 47 |
| Total gains in net income | **$ 1,037** | $ 64 |

As at December 31, 2023, 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) | 296 | 80 | 50 | 38 | 30 |
| Natural gas sales (Mmbtu) | 338 | 86 | 16 | 6 | 4 |
| Power purchases (MWh) | 1 | – | – | – | – |
| Power sales (MWh) | 1 | – | – | – | – |

## OTHER DERIVATIVES

As at December 31, 2023, the Company had equity derivatives in place to manage the 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 $508 million USD and expire in 2023, 2024 and 2025.

| For the<br>millions of dollars | | | | Year ended December 31 |
|---|---|---|---|---|
| | **2023** | | 2022 | |
| | **FX Forwards** | **Equity Derivatives** | FX Forwards | Equity Derivatives |
| Unrealized gain (loss) in OM&G | **$ –** | **$ 4** | $ – | $ (5) |
| Unrealized gain (loss) in other income, net | **28** | **–** | (18) | – |
| Realized loss in OM&G | **–** | **(13)** | – | (17) |
| Realized loss in other income, net | **(11)** | **–** | (6) | – |
| Total gains (losses) in net income | **$ 17** | **$ (9)** | $ (24) | $ (22) |

## CREDIT RISK

The Company is exposed to credit risk with respect to amounts receivable from customers, energy marketing collateral deposits and derivative assets. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties, and deposits or collateral are requested on any high-risk accounts.

The Company assesses the potential for credit losses on a regular basis and, where appropriate, maintains provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

As at December 31, 2023, the maximum exposure the Company had to credit risk was $1.2 billion (2022 – $1.9 billion), which included accounts receivable net of collateral/deposits and assets related to derivatives.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price, 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 total cash deposits/collateral on hand as at December 31, 2023 was $310 million (2022 – $386 million), which mitigated the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International Swaps and Derivatives Association agreements, 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 December 31, 2023, the Company had $142 million (2022 – $131 million) in financial assets, considered to be past due, which have been outstanding for an average 64 days. The FV of these financial assets was $127 million (2022 – $114 million), the difference of which was included in the allowance for credit losses. These assets primarily relate to accounts receivable from electric and gas revenue.

### CONCENTRATION RISK

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

| As at | | **December 31, 2023** | | December 31, 2022 |
|---|---|---|---|---|
| | **millions of dollars** | **% of total exposure** | millions of dollars | % of total exposure |
| **Receivables, net** | | | | |
| *Regulated utilities:* | | | | |
| Residential | **$ 476** | **31%** | $ 455 | 19% |
| Commercial | **194** | **13%** | 192 | 8% |
| Industrial | **84** | **5%** | 121 | 5% |
| Other | **103** | **7%** | 122 | 5% |
| Cash collateral | **94** | **6%** | – | 0% |
| | **951** | **62%** | 890 | 37% |
| *Trading group:* | | | | |
| Credit rating of A- or above | **47** | **3%** | 125 | 5% |
| Credit rating of BBB- to BBB+ | **33** | **2%** | 75 | 3% |
| Not rated | **108** | **7%** | 307 | 13% |
| | **188** | **12%** | 507 | 21% |
| Other accounts receivable | **151** | **10%** | 585 | 25% |
| | **1,290** | **84%** | 1,982 | 83% |
| **Derivative Instruments** (current and long-term) | | | | |
| Credit rating of A- or above | **138** | **9%** | 202 | 9% |
| Credit rating of BBB- to BBB+ | **7** | **1%** | 8 | 0% |
| Not rated | **95** | **6%** | 186 | 8% |
| | **240** | **16%** | 396 | 17% |
| | **$ 1,530** | **100%** | $ 2,378 | 100% |

### CASH COLLATERAL

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

| As at<br>millions of dollars | **December 31 2023** | December 31 2022 |
|---|---|---|
| Cash collateral provided to others | **$ 101** | $ 224 |
| Cash collateral received from others | **$ 22** | $ 112 |

Collateral is posted in the normal course of business based on the Company's creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt falling below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at December 31, 2023, the total FV of derivatives in a liability position was $504 million (December 31, 2022 – $1,078 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.

## 16. FV Measurements

The Company is required to determine the FV of all derivatives except those which qualify for the NPNS exemption (see note 1) 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<br>millions of dollars | Level 1 | Level 2 | Level 3 | December 31, 2023<br>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:* | | | | |
| FX forwards | – | 18 | – | 18 |
| Equity derivatives | 4 | – | – | 4 |
| | 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 |
| | – | 7 | – | 7 |
| **Total liabilities** | 56 | 83 | 365 | 504 |
| **Net assets (liabilities)** | $ (8) | $ 75 | $ (331) | $ (264) |

| As at<br>millions of dollars | Level 1 | Level 2 | Level 3 | December 31, 2022<br>Total |
|---|---|---|---|---|
| **Assets** | | | | |
| *Regulatory deferral:* | | | | |
| Commodity swaps and forwards | $ 120 | $ 48 | $ – | $ 168 |
| FX forwards | – | 18 | – | 18 |
| Physical natural gas purchases and sales | – | – | 52 | 52 |
| | 120 | 66 | 52 | 238 |
| *HFT derivatives:* | | | | |
| Power swaps and physical contracts | 9 | 31 | 4 | 44 |
| Natural gas swaps, futures, forwards, physical contracts and related transportation | 3 | 72 | 34 | 109 |
| | 12 | 103 | 38 | 153 |
| *Other derivatives:* | | | | |
| FX forwards | – | 5 | – | 5 |
| **Total assets** | 132 | 174 | 90 | 396 |
| **Liabilities** | | | | |
| *Regulatory deferral:* | | | | |
| Commodity swaps and forwards | 15 | 9 | – | 24 |
| FX forwards | – | 1 | – | 1 |
| | 15 | 10 | – | 25 |
| *HFT derivatives:* | | | | |
| Power swaps and physical contracts | 2 | 28 | 1 | 31 |
| Natural gas swaps, futures, forwards and physical contracts | 51 | 118 | 825 | 994 |
| | 53 | 146 | 826 | 1,025 |
| *Other derivatives:* | | | | |
| FX forwards | – | 23 | – | 23 |
| Equity derivatives | 5 | – | – | 5 |
| **Total liabilities** | 73 | 179 | 826 | 1,078 |
| **Net assets (liabilities)** | $ 59 | $ (5) | $ (736) | $ (682) |

The change in the FV of the Level 3 financial assets for the year ended December 31, 2023 was as follows:

| | **Regulatory Deferral** | **HFT Derivatives** | | |
|---|---|---|---|---|
| millions of dollars | **Physical natural gas purchases** | **Power** | **Natural gas** | **Total** |
| Balance, January 1, 2023 | **$ 52** | **$ 4** | **$ 34** | **$ 90** |
| Realized gains (losses) included in fuel for generation and purchased power | **(49)** | **–** | **–** | **(49)** |
| Unrealized gains (losses) included in regulatory assets and liabilities | **(3)** | **–** | **–** | **(3)** |
| Total realized and unrealized gains (losses) included in non-regulated operating revenues | **–** | **(4)** | **–** | **(4)** |
| Balance, December 31, 2023 | **$ –** | **$ –** | **$ 34** | **$ 34** |

The change in the FV of the Level 3 financial liabilities for the year ended December 31, 2023 was as follows:

| | **HFT Derivatives** | | |
|---|---|---|---|
| millions of dollars | **Power** | **Natural gas** | **Total** |
| Balance, January 1, 2023 | **$ 1** | **$ 825** | **$ 826** |
| Total realized and unrealized gains included in non-regulated operating revenues | **(1)** | **(460)** | **(461)** |
| Balance, December 31, 2023 | **$ –** | **$ 365** | **$ 365** |

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:

| millions of dollars | FV | | Significant Unobservable Input | Low | High | Weighted average (1) |
|---|---|---|---|---|---|---|
| | Assets | Liabilities | | | | |
| **As at December 31, 2023** | | | | | | |
| HFT derivatives – Natural gas swaps, futures, forwards and physical contracts | **34** | **365** | Third-party pricing | $ 1.27 | $ 16.25 | $ 4.85 |
| **Total** | **$ 34** | **$ 365** | | | | |
| **Net liability** | | **$ 331** | | | | |
| **As at December 31, 2022** | | | | | | |
| Regulatory deferral – Physical natural gas purchases | $ 52 | $ – | Third-party pricing | $ 5.79 | $ 31.85 | $ 12.27 |
| HFT derivatives – Power swaps and physical contracts | 4 | 1 | Third-party pricing | $ 43.24 | $ 269.10 | $ 138.79 |
| HFT derivatives – Natural gas swaps, futures, forwards and physical contracts | 34 | 825 | Third-party pricing | $ 2.45 | $ 33.88 | $ 12.01 |
| **Total** | $ 90 | $ 826 | | | | |
| **Net liability** | | $ 736 | | | | |

(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 Consolidated Balance Sheets. The balance consisted of the following:

| As at<br>millions of dollars | Carrying Amount | FV | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|---|---|
| **December 31, 2023** | **$ 18,365** | **$ 16,621** | **$ –** | **$ 16,363** | **$ 258** | **$ 16,621** |
| December 31, 2022 | $ 16,318 | $ 14,670 | $ – | $ 14,284 | $ 386 | $ 14,670 |

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. The Company's Hybrid Notes are contingently convertible into preferred shares in the event of bankruptcy or other related events. A redemption option on or after June 15, 2026 is available and at the control of the Company. The Hybrid Notes are classified as Level 2 financial assets. As at December 31, 2023, the FV of the Hybrid Notes was $1.2 billion (2022 – $1.1 billion). An after-tax foreign currency gain of $38 million was recorded in AOCI for the year ended December 31, 2023 (2022 – $97 million after-tax loss).

## 17. 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 Consolidated Statements of Income. NSPI's expense is reported in Regulated fuel for generation and purchased power, totalling $163 million for the year ended December 31, 2023 (2022 – $157 million). NSPML is accounted for as an equity investment, and therefore 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 Consolidated Statements of Income. Purchases from M&NP reported net in Operating revenues, Non-regulated, totalled $14 million for the year ended December 31, 2023 (2022 – $9 million).

There were no significant receivables or payables between Emera and its associated companies reported on Emera's Consolidated Balance Sheets as at December 31, 2023 and at December 31, 2022.

## 18. Receivables and Other Current Assets

| As at<br>millions of dollars | **December 31 2023** | December 31 2022 |
|---|---|---|
| Customer accounts receivable – billed | **$ 805** | $ 1,096 |
| Capitalized transportation capacity (1) | **358** | 781 |
| Customer accounts receivable – unbilled | **363** | 424 |
| Prepaid expenses | **105** | 82 |
| Income tax receivable | **10** | 9 |
| Allowance for credit losses | **(15)** | (17) |
| NMGC gas hedge settlement receivable (2) | **–** | 162 |
| Other | **191** | 360 |
| Total receivables and other current assets | **$ 1,817** | $ 2,897 |

(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.

(2) Offsetting amount is included in regulatory liabilities for NMGC as gas hedges are part of the PGAC. For more information, refer to note 6.

# 19. Leases

## LESSEE

The Company has operating leases for buildings, land, telecommunication services, and rail cars. Emera's leases have remaining lease terms of 1 year to 62 years, some of which include options to extend the leases for up to 65 years. These options are included as part of the lease term when it is considered reasonably certain they will be exercised.

| As at<br>millions of dollars | Classification | | **December 31<br>2023** | | December 31<br>2022 |
|---|---|---|---|---|---|
| Right-of-use asset | Other long-term assets | **$** | **54** | $ | 58 |
| Lease liabilities | | | | | |
| Current | Other current liabilities | | **3** | | 3 |
| Long-term | Other long-term liabilities | | **55** | | 59 |
| Total lease liabilities | | **$** | **58** | $ | 62 |

The Company recorded lease expense of $127 million for the year ended December 31, 2023 (2022 – $138 million), of which $119 million (2022 – $131 million) related to variable costs for power generation facility finance leases, recorded in "Regulated fuel for generation and purchased power" in the Consolidated Statements of Income.

Future minimum lease payments under non-cancellable operating leases for each of the next five years and in aggregate thereafter are as follows:

| millions of dollars | | 2024 | | 2025 | | 2026 | | 2027 | | 2028 | | Thereafter | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Minimum lease payments | $ | 6 | $ | 5 | $ | 3 | $ | 3 | $ | 3 | $ | 111 | $ | 131 |
| Less imputed interest | | | | | | | | | | | | | | (73) |
| Total | | | | | | | | | | | | | $ | 58 |

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

| For the | Year ended December 31<br>**2023** | | | 2022 |
|---|---|---|---|---|
| Cash paid for amounts included in the measurement of lease liabilities: | | | | |
| Operating cash flows for operating leases (millions of dollars) | **$** | **8** | $ | 8 |
| Right-of-use assets obtained in exchange for lease obligations: | | | | |
| Operating leases (millions of dollars) | **$** | **1** | $ | 1 |
| Weighted average remaining lease term (years) | | **44** | | 44 |
| Weighted average discount rate – operating leases | | **3.93%** | | 3.98% |

## LESSOR

The Company's net investment in direct finance and sales-type leases primarily relates to Brunswick Pipeline, Seacoast, compressed natural gas ("CNG") stations, a renewable natural gas ("RNG") facility and heat pumps.

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

Customers have the option to purchase CNG station assets by paying a make-whole payment at the date of the purchase based on a targeted internal rate of return or may take possession of the CNG station asset at the end of the lease term for no cost. Customers have the option to purchase heat pumps at the end of the lease term for a nominal fee.

Commencing in October 2023, the Company leased a RNG facility to a biogas producer that is classified as a sales-type lease. The term of the facility lease is 15 years, with a nominal value purchase at the end of the term and a net investment of approximately $35 million USD.

Commencing in January 2022, the Company leased Seacoast pipeline, a 21-mile, 30-inch lateral that is classified as a sales-type lease. The term of the pipeline lateral lease is 34 years with a net investment of $100 million USD. The lessee of the pipeline lateral has renewal options for an additional 16 years. These renewal options have not been included as part of the pipeline lateral lease term as it is not reasonably certain that they will be exercised.

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

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

| As at<br>millions of dollars | **December 31<br>2023** | December 31<br>2022 |
|---|---|---|
| Total minimum lease payment to be received | **$ 1,360** | $ 1,393 |
| Less: amounts representing estimated executory costs | **(190)** | (205) |
| Minimum lease payments receivable | **$ 1,170** | $ 1,188 |
| Estimated residual value of leased property (unguaranteed) | **183** | 183 |
| Less: Credit loss reserve | **(2)** | – |
| Less: unearned finance lease income | **(693)** | (733) |
| Net investment in direct finance and sales-type leases | **$ 658** | $ 638 |
| Principal due within one year (included in "Receivables and other current assets") | **37** | 34 |
| Net Investment in direct finance and sales type leases – long-term | **$ 621** | $ 604 |

As at December 31, 2023, future minimum lease payments to be received for each of the next five years and in aggregate thereafter were as follows:

| millions of dollars | 2024 | 2025 | 2026 | 2027 | 2028 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Minimum lease payments to be received | $ 97 | $ 99 | $ 98 | $ 97 | $ 96 | $ 873 | $ 1,360 |
| Less: executory costs | | | | | | | (190) |
| Total | | | | | | | $ 1,170 |

## 20. Property, Plant and Equipment

PP&E consisted of the following regulated and non-regulated assets:

| As at<br>millions of dollars | Estimated useful life | **December 31<br>2023** | December 31<br>2022 |
|---|---|---|---|
| Generation | 3 to 131 | **$ 13,500** | $ 13,083 |
| Transmission | 10 to 80 | **2,835** | 2,731 |
| Distribution | 4 to 80 | **7,417** | 6,978 |
| Gas transmission and distribution | 6 to 92 | **5,536** | 5,061 |
| General plant and other (1) | 2 to 71 | **2,985** | 2,723 |
| Total cost | | **32,273** | 30,576 |
| Less: Accumulated depreciation (1) | | **(9,994)** | (9,574) |
| | | **22,279** | 21,002 |
| Construction work in progress (1) | | **2,097** | 1,994 |
| Net book value | | **$ 24,376** | $ 22,996 |

(1) SeaCoast owns a 50% undivided ownership interest in a jointly owned 26-mile pipeline lateral located in Florida, which went into service in 2020. At December 31, 2023, SeaCoast's share of plant in service was $27 million USD (2022 – $27 million USD), and accumulated depreciation of $2 million USD (2022 – $1 million USD). SeaCoast's undivided ownership interest is financed with its funds and all operations are accounted for as if such participating interest were a wholly owned facility. SeaCoast's share of direct expenses of the jointly owned pipeline is included in "OM&G" in the Consolidated Statements of Income.

# 21. 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:

## BENEFIT OBLIGATION AND PLAN ASSETS

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

| For the millions of dollars | | | Year ended December 31 | |
|---|---|---|---|---|
| | **2023** | | 2022 | |
| **Change in Projected Benefit Obligation ("PBO") and Accumulated Post-retirement Benefit Obligation ("APBO")** | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefit plans |
| Balance, January 1 | **$ 2,158** | **$ 243** | $ 2,624 | $ 318 |
| Service cost | **30** | **3** | 41 | 4 |
| Plan participant contributions | **6** | **6** | 6 | 6 |
| Interest cost | **111** | **13** | 80 | 9 |
| Plan amendments | **–** | **(14)** | – | – |
| Benefits paid | **(147)** | **(29)** | (174) | (31) |
| Actuarial losses (gains) | **146** | **10** | (480) | (79) |
| Settlements and curtailments | **(8)** | **–** | (6) | – |
| FX translation adjustment | **(23)** | **(5)** | 67 | 16 |
| Balance, December 31 | **$ 2,273** | **$ 227** | $ 2,158 | $ 243 |
| **Change in plan assets** | | | | |
| Balance, January 1 | **$ 2,163** | **$ 46** | $ 2,702 | $ 51 |
| Employer contributions | **42** | **23** | 45 | 24 |
| Plan participant contributions | **6** | **6** | 6 | 6 |
| Benefits paid | **(147)** | **(29)** | (174) | (31) |
| Actual return on assets, net of expenses | **262** | **3** | (489) | (7) |
| Settlements and curtailments | **(8)** | **–** | (6) | – |
| FX translation adjustment | **(20)** | **(1)** | 79 | 3 |
| Balance, December 31 | **$ 2,298** | **$ 48** | $ 2,163 | $ 46 |
| Funded status, end of year | **$ 25** | **$ (179)** | $ 5 | $ (197) |

The actuarial losses recognized in the period are primarily due to changes in the discount rate, higher than expected indexation, and compensation-related assumption changes.

## PLANS WITH PBO/APBO IN EXCESS OF PLAN ASSETS

The aggregate financial position for all pension plans where the PBO or APBO (for post-retirement benefit plans) exceeded the plan assets for the years ended December 31 was as follows:

| millions of dollars | **2023** | | 2022 | |
|---|---|---|---|---|
| | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefit plans |
| PBO/APBO | **$ 120** | **$ 205** | $ 1,006 | $ 221 |
| FV of plan assets | **37** | **–** | 914 | – |
| Funded status | **$ (83)** | **$ (205)** | $ (92) | $ (221) |

## PLANS WITH ACCUMULATED BENEFIT OBLIGATION ("ABO") IN EXCESS OF PLAN ASSETS

The ABO for the DB pension plans was $2,172 million as at December 31, 2023 (2022 – $2,080 million). The aggregate financial position for those plans with an ABO in excess of the plan assets for the years ended December 31 was as follows:

| millions of dollars | 2023 | 2022 |
|---|---|---|
| | **Defined benefit pension plans** | Defined benefit pension plans |
| ABO | **$ 114** | $ 111 |
| FV of plan assets | **37** | 33 |
| Funded status | **$ (77)** | $ (78) |

## BALANCE SHEET

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

| As at<br>millions of dollars | | **December 31 2023** | | December 31 2022 |
|---|---|---|---|---|
| | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefit plans |
| Other current liabilities | **$ (5)** | **$ (18)** | $ (13) | $ (20) |
| Long-term liabilities | **(78)** | **(187)** | (80) | (201) |
| Other long-term assets | **108** | **26** | 98 | 24 |
| AOCI, net of tax and regulatory assets | **385** | **20** | 358 | 22 |
| Less: Deferred income tax (expense) recovery in AOCI | **(8)** | **(1)** | (7) | (1) |
| Net amount recognized | **$ 402** | **$ (160)** | $ 356 | $ (176) |

## AMOUNTS RECOGNIZED IN AOCI AND REGULATORY ASSETS

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCI or regulatory assets. The following table summarizes the change in AOCI and regulatory assets:

| millions of dollars | Regulatory assets | Actuarial (gains) losses | Past service (gains) costs |
|---|---|---|---|
| **Defined Benefit Pension Plans** | | | |
| Balance, January 1, 2023 | $ 336 | $ 15 | $ – |
| Amortized in current period | (6) | (3) | – |
| Current year additions | 1 | 41 | – |
| Change in FX rate | (7) | – | – |
| Balance, December 31, 2023 | $ 324 | $ 53 | $ – |
| **Non-pension benefits plans** | | | |
| Balance, January 1, 2023 | $ 31 | $ (10) | $ – |
| Amortized in current period | 2 | 3 | – |
| Current year reductions | (3) | (1) | (3) |
| Change in FX rate | (1) | – | 1 |
| Balance, December 31, 2023 | $ 29 | $ (8) | $ (2) |

| As at<br>millions of dollars | December 2023 | | December 2022 | |
|---|---|---|---|---|
| | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefit plans |
| Actuarial losses (gains) | **$ 53** | **$ (8)** | $ 15 | $ (10) |
| Past service gains | **–** | **(2)** | – | – |
| Deferred income tax expense | **8** | **1** | 7 | 1 |
| AOCI, net of tax | **61** | **(9)** | 22 | (9) |
| Regulatory assets | **324** | **29** | 336 | 31 |
| AOCI, net of tax and regulatory assets | **$ 385** | **$ 20** | $ 358 | $ 22 |

## BENEFIT COST COMPONENTS

Emera's net periodic benefit cost included the following:

| As at<br>millions of dollars | Year ended December 31<br>2023 | | 2022 | |
|---|---|---|---|---|
| | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefit plans |
| Service cost | **$ 30** | **$ 3** | $ 41 | $ 4 |
| Interest cost | **111** | **13** | 80 | 9 |
| Expected return on plan assets | **(161)** | **(2)** | (144) | – |
| Current year amortization of: | | | | |
| Actuarial losses (gains) | **1** | **(3)** | 8 | – |
| Regulatory assets (liability) | **6** | **(2)** | 21 | 2 |
| Settlement, curtailments | **2** | **–** | 2 | – |
| Total | **$ (11)** | **$ 9** | $ 8 | $ 15 |

The expected return on plan assets is determined based on the market-related value of plan assets of $2,577 million as at January 1, 2023 (2022 – $2,482 million), adjusted for interest on certain cash flows during the year. The market-related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight-line basis into the market-related value of assets over a five-year period.

## PENSION PLAN ASSET ALLOCATIONS

Emera's investment policy includes discussion regarding the investment philosophy, the level of risk which the Company is prepared to accept with respect to the investment of the Pension Funds, and the basis for measuring the performance of the assets. Central to the policy is the target asset allocation by major asset categories. The objective of the target asset allocation is to diversify risk and to achieve asset returns that meet or exceed the plan's actuarial assumptions. The diversification of assets reduces the inherent risk in financial markets by requiring that assets be spread out amongst various asset classes. Within each asset class, a further diversification is undertaken through the investment in a broad range of investment and non-investment grade securities. Emera's target asset allocation is as follows:

### Canadian Pension Plans

| Asset class | Target Range at Market |
|---|---|
| Short-term securities | 0% to 10% |
| Fixed income | 34% to 49% |
| Equities: | |
| Canadian | 7% to 17% |
| Non-Canadian | 35% to 59% |

## Non-Canadian Pension Plans

| Asset class | Target Range at Market Weighted Average |
|---|---|
| Cash and cash equivalents | 0% to 10% |
| Fixed income | 29% to 49% |
| Equities | 48% to 68% |

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

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

| millions of dollars | NAV | Level 1 | Level 2 | Total | Percentage |
|---|---|---|---|---|---|
| As at | | | | | **December 31, 2023** |
| Cash and cash equivalents | **$ –** | **$ 40** | **$ –** | **$ 40** | **2%** |
| Net in-transits | **–** | **(9)** | **–** | **(9)** | **–%** |
| Equity securities: | | | | | |
| Canadian equity | **–** | **96** | **–** | **96** | **4%** |
| United States equity | **–** | **141** | **–** | **141** | **6%** |
| Other equity | **–** | **112** | **–** | **112** | **5%** |
| Fixed income securities: | | | | | |
| Government | **–** | **-** | **172** | **172** | **8%** |
| Corporate | **–** | **-** | **90** | **90** | **4%** |
| Other | **–** | **4** | **5** | **9** | **–%** |
| Mutual funds | **–** | **50** | **-** | **50** | **2%** |
| Other | **–** | **6** | **(1)** | **5** | **–%** |
| Open-ended investments measured at NAV (1) | **1,006** | **-** | **-** | **1,006** | **44%** |
| Common collective trusts measured at NAV (2) | **586** | **-** | **-** | **586** | **25%** |
| Total | **$ 1,592** | **$ 440** | **$ 266** | **$ 2,298** | **100%** |

| millions of dollars | NAV | Level 1 | Level 2 | Total | Percentage |
|---|---|---|---|---|---|
| As at | | | | | December 31, 2022 |
| Cash and cash equivalents | $ – | $ 70 | $ – | $ 70 | 3% |
| Net in-transits | – | (70) | – | (70) | (3)% |
| Equity securities: | | | | | |
| Canadian equity | – | 87 | – | 87 | 4% |
| United States equity | – | 233 | – | 233 | 11% |
| Other equity | – | 186 | – | 186 | 8% |
| Fixed income securities: | | | | | |
| Government | – | – | 104 | 104 | 5% |
| Corporate | – | – | 83 | 83 | 4% |
| Other | – | 3 | 11 | 14 | 1% |
| Mutual funds | – | 68 | – | 68 | 3% |
| Other | – | – | (3) | (3) | –% |
| Open-ended investments measured at NAV (1) | 790 | – | – | 790 | 36% |
| Common collective trusts measured at NAV (2) | 601 | – | – | 601 | 28% |
| Total | $ 1,391 | $ 577 | $ 195 | $ 2,163 | 100% |

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

Refer to note 16 for more information on the FV hierarchy and inputs used to measure FV.

## POST-RETIREMENT BENEFIT PLANS

There are no assets set aside to pay for most of the Company's post-retirement benefit plans. As is common practice, post-retirement health benefits are paid from general accounts as required. The primary exception to this is the NMGC Retiree Medical Plan, which is fully funded.

## INVESTMENTS IN EMERA

As at December 31, 2023 and 2022, assets related to the pension funds and post-retirement benefit plans did not hold any material investments in Emera or its subsidiaries securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

## CASH FLOWS

The following table shows expected cash flows for DB pension and other post-retirement benefit plans:

| millions of dollars | Defined benefit pension plans | Non-pension benefit plans |
|---|---|---|
| **Expected employer contributions** | | |
| 2024 | $ 34 | $ 19 |
| **Expected benefit payments** | | |
| 2024 | 172 | 21 |
| 2025 | 163 | 21 |
| 2026 | 166 | 21 |
| 2027 | 171 | 21 |
| 2028 | 173 | 20 |
| 2029–2033 | 890 | 95 |

## ASSUMPTIONS

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

| | | **2023** | | 2022 |
|---|---|---|---|---|
| (weighted average assumptions) | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefit plans |
| **Benefit obligation – December 31:** | | | | |
| Discount rate – past service | **4.89%** | **4.89%** | 5.33% | 5.31% |
| Discount rate – future service | **4.88%** | **4.89%** | 5.34% | 5.32% |
| Rate of compensation increase | **3.87%** | **3.85%** | 3.62% | 3.61% |
| Health care trend – initial (next year) | **–** | **6.04%** | – | 5.40% |
| – ultimate | **–** | **3.76%** | – | 3.77% |
| – year ultimate reached | | **2043** | | 2043 |
| **Benefit cost for year ended December 31:** | | | | |
| Discount rate – past service | **5.33%** | **5.31%** | 3.05% | 2.81% |
| Discount rate – future service | **5.34%** | **5.32%** | 3.18% | 2.92% |
| Expected long-term return on plan assets | **6.56%** | **2.16%** | 6.07% | 1.32% |
| Rate of compensation increase | **3.62%** | **3.61%** | 3.31% | 3.29% |
| Health care trend – initial (current year) | **–** | **5.40%** | – | 5.09% |
| – ultimate | **–** | **3.77%** | – | 3.77% |
| – year ultimate reached | | **2043** | | 2042 |

Actual assumptions used differ by plan.

The expected long-term rate of return on plan assets is based on historical and projected real rates of return for the plan's current asset allocation, and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined. The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

The discount rate is based on high-quality long-term corporate bonds, with maturities matching the estimated cash flows from the pension plan.

### DEFINED CONTRIBUTION PLAN

Emera also provides a DC pension plan for certain employees. The Company's contribution for the year ended December 31, 2023 was $45 million (2022 – $41 million).

## 22. Goodwill

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

| millions of dollars | **2023** | 2022 |
|---|---|---|
| Balance, January 1 | **$ 6,012** | $ 5,696 |
| Change in FX rate | **(141)** | 389 |
| GBPC impairment charge | **–** | (73) |
| Balance, December 31 | **$ 5,871** | $ 6,012 |

Goodwill is subject to an annual assessment for impairment at the reporting unit level. The goodwill on Emera's Consolidated Balance Sheets at December 31, 2023, primarily related to TECO Energy (reporting units with goodwill are TEC, PGS, and NMGC).

In 2023, Emera performed qualitative impairment assessments for NMGC and PGS, concluding that the FV of the reporting units exceeded their respective carrying amounts, and as such, no quantitative assessments were performed and no impairment charges were recognized. Given the length of time passed since the last quantitative impairment test for the TEC reporting unit, Emera elected to bypass a qualitative assessment and performed a quantitative impairment assessment in Q4 2023 using a combination of the income approach and market approach. This assessment estimated that the FV of the TEC reporting unit exceeded its carrying amount, including goodwill, and as a result no impairment charges were recognized.

In 2022, the Company elected to bypass a qualitative assessment and performed a quantitative impairment assessment for GBPC, using the income approach. It was determined that the FV did not exceed its carrying amount, including goodwill. As a result of this assessment, a goodwill impairment charge of $73 million was recorded in 2022, reducing the GBPC goodwill balance to nil as at December 31, 2022. This non-cash charge is included in "GBPC impairment charge" on the Consolidated Statements of Income.

## 23. Short-Term Debt

Emera's short-term borrowings consist of commercial paper issuances, advances on revolving and non-revolving credit facilities and short-term notes. Short-term debt and the related weighted-average interest rates as at December 31 consisted of the following:

| millions of dollars | 2023 | Weighted average interest rate | 2022 | Weighted average interest rate |
|---|---|---|---|---|
| **TEC** | | | | |
| Advances on revolving credit facilities | **$ 277** | **5.68%** | $ 1,380 | 5.00% |
| **Emera** | | | | |
| Non-revolving term facilities | **796** | **6.07%** | 796 | 5.19% |
| Bank indebtedness | **9** | **-%** | – | –% |
| **TECO Finance** | | | | |
| Advances on revolving credit and term facilities | **245** | **6.54%** | 481 | 5.47% |
| **PGS** | | | | |
| Advances on revolving credit facilities | **73** | **6.36%** | – | –% |
| **NMGC** | | | | |
| Advances on revolving credit facilities | **25** | **6.46%** | 59 | 5.15% |
| **GBPC** | | | | |
| Advances on revolving credit facilities | **8** | **5.54%** | 10 | 5.25% |
| **Short-term debt** | **$ 1,433** | | $ 2,726 | |

The Company's total short-term revolving and non-revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

| millions of dollars | Maturity | 2023 | 2022 |
|---|---|---|---|
| TEC – Unsecured committed revolving credit facility | 2026 | **$ 401** | $ 1,084 |
| TECO Energy/TECO Finance – revolving credit facility | 2026 | **–** | 542 |
| TECO Finance – Unsecured committed revolving credit facility | 2026 | **529** | – |
| Emera – Unsecured non-revolving term facility | 2024 | **400** | 400 |
| Emera – Unsecured non-revolving term facility | 2024 | **400** | 400 |
| PGS – Unsecured revolving credit facility | 2028 | **331** | – |
| TEC – Unsecured revolving facility | 2024 | **265** | 542 |
| TEC – Unsecured revolving facility | 2024 | **265** | – |
| NMGC – Unsecured revolving credit facility | 2026 | **165** | 169 |
| Other – Unsecured committed revolving credit facilities | Various | **17** | 18 |
| Total | | **$ 2,773** | $ 3,155 |
| Less: | | | |
| Advances under revolving credit and term facilities | | **1,433** | 2,731 |
| Letters of credit issued within the credit facilities | | **3** | 4 |
| Total advances under available facilities | | **1,436** | 2,735 |
| Available capacity under existing agreements | | **$ 1,337** | $ 420 |

The weighted average interest rate on outstanding short-term debt at December 31, 2023 was 5.95 per cent (2022 – 5.01 per cent).

## RECENT SIGNIFICANT FINANCING ACTIVITY BY SEGMENT

### Florida Electric Utilities

On November 24, 2023, TEC repaid its $400 million USD unsecured non-revolving facility, which expired on December 13, 2023.

On April 3, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on April 1, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term secured overnight financing rate ("SOFR"), Wells Fargo's prime rate, the federal funds rate or the one-month SOFR, plus a margin.

On March 1, 2023, TEC entered into a 364-day, $200 million USD senior unsecured revolving credit facility which matures on February 28, 2024. The credit facility contains customary representations and warranties, events of default and financial and other covenants, and bears interest at a variable interest rate, based on either the term SOFR, the Bank of Nova Scotia's prime rate, the federal funds rate or the one-month SOFR, plus a margin.

### Gas Utilities and Infrastructure

On December 1, 2023, PGS entered into a $250 million USD senior unsecured revolving credit facility with a group of banks, maturing on December 1, 2028. PGS has the ability to request the lenders to increase their commitments under the credit facility by up to $100 million USD in the aggregate subject to agreement from participating lenders. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin.

### Other

On December 16, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from December 16, 2023 to December 16, 2024. There were no other changes in commercial terms from the prior agreement.

On June 30, 2023, Emera amended its $400 million unsecured non-revolving facility to extend the maturity date from August 2, 2023 to August 2, 2024. There were no other changes in commercial terms from the prior agreement.

# 24. Other Current Liabilities

| As at<br>millions of dollars | **December 31<br>2023** | December 31<br>2022 |
|---|---|---|
| Accrued charges | **$ 172** | $ 174 |
| Nova Scotia Cap-and-Trade Program provision (note 6) | **–** | 172 |
| Accrued interest on long-term debt | **107** | 97 |
| Pension and post-retirement liabilities (note 21) | **23** | 33 |
| Sales and other taxes payable | **11** | 14 |
| Income tax payable | **2** | 9 |
| Other | **112** | 80 |
| | **$ 427** | $ 579 |

## 25. Long-Term Debt

Bonds, notes and debentures are at fixed interest rates and are unsecured unless noted below. Included are certain bankers' acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year.

Long-term debt as at December 31 consisted of the following:

| | Weighted average interest rate (1) | | | | |
|---|---|---|---|---|---|
| millions of dollars | 2023 | 2022 | Maturity | **2023** | 2022 |
| **Emera** | | | | | |
| Bankers acceptances, SOFR loans | Variable | Variable | 2027 | **$ 465** | $ 403 |
| Unsecured fixed rate notes | 4.84% | 2.90% | 2030 | **500** | 500 |
| Fixed to floating subordinated notes (USD) (2) | 6.75% | 6.75% | 2076 | **1,587** | 1,625 |
| | | | | **$ 2,552** | $ 2,528 |
| **Emera Finance** | | | | | |
| Unsecured senior notes | 3.65% | 3.65% | 2024–2046 | **$ 3,637** | $ 3,725 |
| **TEC** (3) | | | | | |
| Fixed rate notes and bonds | 4.61% | 4.15% | 2024–2051 | **$ 5,654** | $ 4,341 |
| **PGS** | | | | | |
| Fixed rate notes and bonds | 5.63% | 3.78% | 2028–2053 | **$ 1,223** | $ 772 |
| **NMGC** | | | | | |
| Fixed rate notes and bonds | 3.78% | 3.11% | 2026–2051 | **$ 642** | $ 521 |
| Non-revolving term facility, floating rate | Variable | Variable | 2024 | **30** | 108 |
| | | | | **$ 672** | $ 629 |
| **NMGI** | | | | | |
| Fixed rate notes and bonds | 3.64% | 3.64% | 2024 | **$ 198** | $ 203 |
| **NSPI** | | | | | |
| Discount Notes (4) | Variable | Variable | 2024–2027 | **$ 721** | $ 881 |
| Medium term fixed rate notes | 5.13% | 5.14% | 2025–2097 | **3,165** | 2,665 |
| | | | | **$ 3,886** | $ 3,546 |
| **EBP** | | | | | |
| Senior secured credit facility | Variable | Variable | 2026 | **$ 246** | $ 249 |
| **ECI** | | | | | |
| Secured senior notes | Variable | Variable | 2027 | **$ 75** | $ 86 |
| Amortizing fixed rate notes | 4.00% | 3.97% | 2026 | **79** | 100 |
| Non-revolving term facility, floating rate | Variable | Variable | 2025 | **29** | 30 |
| Non-revolving term facility, fixed rate | 2.15% | 2.05% | 2025–2027 | **155** | 91 |
| Secured fixed rate senior notes (5) | 3.09% | 3.06% | 2024–2029 | **84** | 142 |
| | | | | **$ 422** | $ 449 |
| **Adjustments** | | | | | |
| Fair market value adjustment – TECO Energy acquisition | | | | **$ -** | $ 2 |
| Debt issuance costs | | | | **(125)** | (126) |
| Amount due within one year | | | | **(676)** | (574) |
| | | | | **$ (801)** | $ (698) |
| **Long-Term Debt** | | | | **$ 17,689** | $ 15,744 |

(1) Weighted average interest rate of fixed rate long-term debt.
(2) In 2023, the Company recognized $109 million in interest expense (2022 – $110 million) related to its fixed to floating subordinated notes.
(3) A substantial part of TEC's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under TEC's first mortgage bond indenture.
(4) Discount notes are backed by a revolving credit facility which matures in 2027. Banker's acceptances are issued under NSPI's non-revolving term facility which matures in 2024. NSPI has the intention and unencumbered ability to refinance bankers' acceptances for a period of greater than one year.
(5) Notes are issued and payable in either USD or BBD.

The Company's total long-term revolving credit facilities, outstanding borrowings and available capacity as at December 31 were as follows:

| millions of dollars | Maturity | | 2023 | | 2022 |
|---|---|---|---|---|---|
| Emera – revolving credit facility [1] | June 2027 | **$** | **900** | $ | 900 |
| TEC – Unsecured committed revolving credit facility | December 2026 | | **657** | | – |
| NSPI – revolving credit facility [1] | December 2027 | | **800** | | 800 |
| NSPI – non-revolving credit facility | July 2024 | | **400** | | 400 |
| Emera – Unsecured non-revolving credit facility | February 2024 | | **400** | | – |
| NMGC – Unsecured non-revolving credit facility | March 2024 | | **30** | | 108 |
| ECI – revolving credit facilities | October 2024 | | **10** | | 11 |
| Total | | **$** | **3,197** | $ | 2,219 |
| Less: | | | | | |
| Borrowings under credit facilities | | | **1,884** | | 1,396 |
| Letters of credit issued inside credit facilities | | | **6** | | 12 |
| Use of available facilities | | **$** | **1,890** | $ | 1,408 |
| Available capacity under existing agreements | | **$** | **1,307** | $ | 811 |

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

## DEBT COVENANTS

Emera and its subsidiaries have debt covenants associated with their credit facilities. Covenants are tested regularly and the Company is in compliance with covenant requirements. Emera's significant covenants are listed below:

| | Financial Covenant | Requirement | As at December 31, 2023 |
|---|---|---|---|
| **Emera** | | | |
| Syndicated credit facilities | Debt to capital ratio | Less than or equal to 0.70 to 1 | 0.57 : 1 |

## RECENT SIGNIFICANT FINANCING ACTIVITY BY SEGMENT

### Florida Electric Utility

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 repayment of short-term borrowings outstanding under the 5-year credit facility. Therefore, $497 million USD of short-term borrowings that were repaid was classified as long-term debt at December 31, 2023.

### Canadian Electric Utilities

On March 24, 2023, NSPI issued $500 million in unsecured notes. The issuance included $300 million unsecured notes that bear interest at 4.95 per cent with a maturity date of November 15, 2032, and $200 million unsecured notes that bear interest at 5.36 per cent with a maturity date of March 24, 2053.

### Gas Utilities and Infrastructure

On December 19, 2023, PGS completed an issuance of $925 million USD in senior notes. The issuance included $350 million USD senior notes that bear interest at 5.42 per cent with a maturity date of December 19, 2028, $350 million USD senior notes that bear interest at 5.63 per cent with a maturity date of December 19, 2033 and $225 million USD senior notes that bear interest at 5.94 per cent with a maturity date of December 19, 2053.

On October 19, 2023, NMGC issued $100 million USD in senior unsecured notes that bear interest at 6.36 per cent with a maturity date of October 19, 2033.

### Other Electric Utilities

On May 24, 2023, GBPC issued a $28 million USD non-revolving term loan that bears interest at 4.00 per cent with a maturity date of May 24, 2028.

### Other

On August 18, 2023, Emera entered into a $400 million non-revolving term facility with a maturity date of February 19, 2024. The credit agreement contains customary representations and warranties, events of default and financial and other covenants, and bears interest at Bankers' Acceptances or prime rate advances, plus a margin. On February 16, 2024, Emera extended the term of this agreement to a maturity date of February 19, 2025.

On May 2, 2023, Emera issued $500 million in senior unsecured notes that bear interest at 4.84 per cent with a maturity date of May 2, 2030.

## LONG-TERM DEBT MATURITIES

As at December 31, long-term debt maturities, including capital lease obligations, for each of the next five years and in aggregate thereafter are as follows:

| millions of dollars | 2024 | 2025 | 2026 | 2027 | 2028 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Emera | $ 199 | $ - | $ 1,587 | $ 266 | $ - | $ 500 | $ 2,552 |
| Emera US Finance LP | 397 | – | 992 | – | – | 2,248 | 3,637 |
| TEC | 397 | – | – | – | – | 5,257 | 5,654 |
| PGS | – | – | – | – | 463 | 760 | 1,223 |
| NMGC | 30 | – | 93 | – | – | 549 | 672 |
| NMGI | 198 | – | – | – | – | – | 198 |
| NSPI | 398 | 125 | 40 | 323 | – | 3,000 | 3,886 |
| EBP | – | – | 246 | – | – | – | 246 |
| ECI | 51 | 139 | 89 | 77 | 62 | 4 | 422 |
| Total | $ 1,670 | $ 264 | $ 3,047 | $ 666 | $ 525 | $ 12,318 | $ 18,490 |

# 26. Asset Retirement Obligations

AROs mostly relate to reclamation of land at the thermal, hydro and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment and a pipeline site. Certain hydro, transmission and distribution assets may have additional AROs that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the FV of any related ARO cannot be made.

The change in ARO for the years ended December 31 is as follows:

| millions of dollars | **2023** | 2022 |
|---|---|---|
| Balance, January 1 | **$ 174** | $ 174 |
| Accretion included in depreciation expense | **9** | 9 |
| Change in FX rate | **(1)** | 3 |
| Additions | **–** | 1 |
| Accretion deferred to regulatory asset (included in PP&E) | **18** | 1 |
| Liabilities settled | **(8)** | (1) |
| Revisions in estimated cash flows | **–** | (13) |
| Balance, December 31 | **$ 192** | $ 174 |

# 27. Commitments and Contingencies

## A. COMMITMENTS

As at December 31, 2023, 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) | $ 696 | $ 495 | $ 405 | $ 388 | $ 338 | $ 2,597 | $ 4,919 |
| Purchased power (2) | 274 | 249 | 263 | 312 | 312 | 3,435 | 4,845 |
| Fuel, gas supply and storage | 556 | 215 | 62 | – | 5 | – | 838 |
| Capital projects | 778 | 111 | 70 | 1 | – | – | 960 |
| Equity investment commitments (3) | 240 | – | – | – | – | – | 240 |
| Other | 154 | 147 | 56 | 46 | 35 | 221 | 659 |
| | $ 2,698 | $ 1,217 | $ 856 | $ 747 | $ 690 | $ 6,253 | $ 12,461 |

(1) Purchasing commitments for transportation of fuel and transportation capacity on various pipelines. Includes a commitment of $134 million related to a gas transportation contract between PGS and SeaCoast through 2040.

(2) Annual requirement to purchase electricity production from IPPs or other utilities over varying contract lengths.

(3) Emera has a commitment to make equity contributions to the LIL related to an investment true up in 2024 and sustaining capital contributions over the life of the partnership. The commercial agreements between Emera and Nalcor require true ups to finalize the respective investment obligations of the parties in relation the Maritime Link and LIL which is expected to be approximately $240 million in 2024. In addition, Emera has future commitments to provide sustaining capital to the LIL for routine capital and major maintenance.

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 February 2022, the UARB issued its decision and Board Order approving NSPML's requested rate base of approximately $1.8 billion. 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.

Construction of the LIL is complete, and the Newfoundland Electrical System Operator confirmed the asset to be operating suitably to support reliable system operation and full functionality at 700MW, which was validated by the Government of Canada's Independent Engineer issuing its Commissioning Certificate on April 13, 2023.

Emera has committed to obtain certain transmission rights for Nalcor, if requested, to enable it to transmit energy which is not otherwise used in Newfoundland and Labrador or Nova Scotia. Nalcor has the right to transmit this energy from Nova Scotia to New England energy markets 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 December 31, 2023, the aggregate financial liability of the Florida utilities is estimated to be $15 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

Emera believes the following principal financial risks could materially affect the Company in the normal course of business. Risks associated with derivative instruments and FV measurements are discussed in note 15 and note 16.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. Emera has an enterprise-wide risk management process, overseen by its Enterprise Risk Management Committee (''ERMC'') and monitored by the Board of Directors, to ensure an effective, consistent and coherent approach to risk management. The Board of Directors has a Risk and Sustainability Committee ('RSC'') with a mandate that includes oversight of the Company's Enterprise Risk Management framework, including the identification, assessment, monitoring and management of enterprise risks. It also includes oversight of the Company's approach to sustainability and its performance relative to its sustainability objectives.

### Regulatory and Political Risk

The Company's rate-regulated subsidiaries and certain investments subject to significant influence are subject to risk of the recovery of costs and investments. Regulatory and political risk can include changes in regulatory frameworks, shifts in government policy, legislative changes, and regulatory decisions.

As cost-of-service utilities with an obligation to serve customers, Emera's utilities operate under formal regulatory frameworks, and must obtain regulatory approval to change or add rates and/or riders. Emera also holds investments in entities in which it has significant influence, and which are subject to regulatory and political risk including NSPML, LIL, and M&NP. As a regulated Group II pipeline, the tolls of Brunswick Pipeline are regulated by the CER on a complaint basis, as opposed to the regulatory approval process described above. In the absence of a complaint, the CER does not normally undertake a detailed examination of Brunswick Pipeline's tolls, which are subject to a firm service agreement, expiring in 2034, with Repsol Energy North America Canada Partnership.

Regulators administer the regulatory frameworks covering material aspects of the utilities' businesses, including applying market-based tests to determine the appropriate customer rates and/or riders, the underlying allowed ROEs, deemed capital structures, capital investment, the terms and conditions for the provision of service, performance standards, and affiliate transactions. Regulators also review the prudency of costs and other decisions that impact customer rates and reliability of service and work to ensure the financial health of the utility for the benefit of customers. Costs and investments can be recovered upon approval by the respective regulator as an adjustment to rates and/or riders, which normally require a public hearing process or may be mandated by other governmental bodies. During public hearing processes, consultants and customer representatives scrutinize the costs, actions and plans of these rate-regulated companies, and their respective regulators determine whether to allow recovery and to adjust rates based upon the evidence and any contrary evidence from other parties. In some circumstances, other government bodies may influence the setting of rates. Regulatory decisions, legislative changes, and prolonged delays in the recovery of costs or regulatory assets could result in decreased rate affordability for customers and could materially affect Emera and its utilities.

Emera's utilities generally manage this risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, regulatory audits, rate filings and capital plans. The subsidiaries work to establish collaborative relationships with regulatory stakeholders, including customer representatives, both through its approach to filings and additional efforts with technical conferences and, where appropriate, negotiated settlements.

Changes in government and shifts in government policy and legislation can impact the commercial and regulatory frameworks under which Emera and its subsidiaries operate. This includes initiatives regarding deregulation or restructuring of the energy industry. Deregulation or restructuring of the energy industry may result in increased competition and unrecovered costs that could adversely affect the Company's operations, net income and cash flows. State and local policies in some United States jurisdictions have sought to prevent or limit the ability of utilities to provide customers the choice to use natural gas while in other jurisdictions policies have been adopted to prevent limitations on the use of natural gas. Changes in applicable state or local laws and regulations, including electrification legislation, could adversely impact PGS and NMGC.

Emera cannot predict future legislative, policy, or regulatory changes, whether caused by economic, political or other factors, or its ability to respond in an effective and timely manner or the resulting compliance costs. Government interference in the regulatory process can undermine regulatory stability, predictability, and independence, and could have a material adverse effect on the Company.

### Foreign Exchange Risk

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

Consistent with the Company's risk management policies, Emera manages currency risks through matching United States denominated debt to finance its United States operations and may use foreign currency derivative instruments to hedge specific transactions and earnings exposure. The Company may enter FX forward and swap contracts to limit exposure on certain foreign currency transactions such as fuel purchases, revenue streams and capital expenditures, and on net income earned outside of Canada. The regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred costs, including FX.

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

### Liquidity and Capital Market Risk

Liquidity risk relates to Emera's ability to ensure sufficient funds are available to meet its financial obligations. Emera manages this risk by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available. Liquidity and capital needs could be financed through internally generated cash flows, asset sales, short-term credit facilities, and ongoing access to capital markets.

Emera's access to capital and cost of borrowing is subject to several risk factors, including financial market conditions, market disruptions and ratings assigned by various market analysts, including credit rating agencies. Disruptions in capital markets could prevent Emera from issuing new securities or cause the Company to issue securities with less than preferred terms and conditions. Emera's growth plan requires significant capital investments in PP&E and the risk associated with changes in interest rates could have an adverse effect on the cost of financing. The Company's future access to capital and cost of borrowing may be impacted by various market disruptions. The inability to access cost-effective capital could have a material impact on Emera's ability to fund its growth plan.

Emera is subject to financial risk associated with changes in its credit ratings. There are a number of factors that rating agencies evaluate to determine credit ratings, including the Company's business, its regulatory framework and legislative environment, political interference in the regulatory process, the ability to recover costs and earn returns, diversification, leverage, liquidity and increased exposure to climate change-related impacts, including increased frequency and severity of hurricanes and other severe weather events. A decrease in a credit rating could result in higher interest rates in future financings, increased borrowing costs under certain existing credit facilities, limit access to the commercial paper market, or limit the availability of adequate credit support for subsidiary operations. For more information on interest rate risk, refer to "General Economic Risk – Interest Rate Risk". For certain derivative instruments, if the credit ratings of the Company were reduced below investment grade, the full value of the net liability of these positions could be required to be posted as collateral. Emera manages these risks by actively monitoring and managing key financial metrics with the objective of sustaining investment grade credit ratings.

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

## General Economic Risk

The Company has exposure to the macro-economic conditions in North America and in other geographic regions in which Emera operates. Like most utilities, economic factors such as consumer income, employment and housing affect demand for electricity and natural gas, and in turn the Company's financial results. Adverse changes in general economic conditions and inflation may impact the ability of customers to afford rate increases arising from increases to fuel, operating, capital, environmental compliance, and other costs, and therefore could materially affect Emera and its utilities. This may also result in higher credit and counterparty risk, adverse shifts in government policy and legislation, and/or increased risk to full and timely recovery of costs and regulatory assets.

### Interest Rate Risk:

Emera utilizes a combination of fixed and floating rate debt financing for operations and capital expenditures, resulting in an exposure to interest rate risk. Emera seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt.

For Emera's regulated subsidiaries, the cost of debt is a component of rates and prudently incurred debt costs are recovered from customers. Regulatory ROE will generally follow the direction of interest rates, such that regulatory ROEs are likely to fall in times of reducing interest rates and rise in times of increasing interest rates, albeit not directly and generally with a lag period reflecting the regulatory process. Rising interest rates may also negatively affect the economic viability of project development and acquisition initiatives.

Interest rates could also be impacted by changes in credit ratings. For more information, refer to "Liquidity and Capital Market Risk".

As with most other utilities and other similar yield-returning investments, Emera's share price may be affected by changes in interest rates and could underperform the market in an environment of rising interest rates.

### Inflation Risk:

The Company may be exposed to changes in inflation that may result in increased operating and maintenance costs, capital investment, and fuel costs compared to the revenues provided by customer rates. Emera's utilities have budgeting and forecasting processes to identify inflationary risk factors and measure operating performance, as well as collective bargaining agreements that mitigate the short-term impact of inflation on labour costs of unionized employees.

## Commodity Price Risk

The Company's utility fuel supply and purchase of other commodities is subject to commodity price risk. In addition, Emera Energy is subject to commodity price risk through its portfolio of commodity contracts and arrangements.

The Company manages this risk through established processes and practices to identify, monitor, report and mitigate these risks. These include the Company's commercial arrangements, such as the combination of supply and purchase agreements, asset management agreements, pipeline transportation agreements and financial hedging instruments. In addition, its credit policies, counterparty credit assessments, market and credit position reporting, and other risk management and reporting practices, are also used to manage and mitigate this risk.

#### Regulated Utilities:

The Company's utility fuel supply is exposed to broader global conditions, which may include impacts on delivery reliability and price, despite contracted terms. Supply and demand dynamics in fuel markets can be affected by a wide range of factors which are difficult to predict and may change rapidly, including but not limited to currency fluctuations, changes in global economic conditions, natural disasters, transportation or production disruptions, and geo-political risks such as political instability, conflicts, changes to international trade agreements, trade sanctions or embargos. The Company seeks to manage this risk using financial hedging instruments and physical contracts and through contractual protection with counterparties, where applicable.

The majority of Emera's regulated electric and gas utilities have adopted and implemented fuel adjustment mechanisms and purchased gas adjustment mechanisms respectively, which further helps manage commodity price risk, as the regulatory framework for the Company's rate-regulated subsidiaries permits the recovery of prudently incurred fuel and gas costs. There is no assurance that such mechanisms and regulatory frameworks will continue to exist in the future. Prolonged and substantial increases in fuel prices could result in decreased rate affordability, increased risk of recovery of costs or regulatory assets, and/or negative impacts on customer consumption patterns and sales.

#### Emera Energy Marketing and Trading:

Emera Energy has employed further measures to manage commodity risk. The majority of Emera Energy's portfolio of electricity and gas marketing and trading contracts and, in particular, its natural gas asset management arrangements, are contracted on a back-to-back basis, avoiding any material long or short commodity positions. However, the portfolio is subject to commodity price risk, particularly with respect to basis point differentials between relevant markets in the event of an operational issue or counterparty default. Changes in commodity prices can also result in increased collateral requirements associated with physical contracts and financial hedges, resulting in higher liquidity requirements and increased costs to the business.

To measure commodity price risk exposure, Emera Energy employs a number of controls and processes, including an estimated VaR analysis of its exposures. The VaR amount represents an estimate of the potential change in FV that could occur from changes in Emera Energy's portfolio or changes in market factors within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with physical commodities, primarily natural gas and power positions.

### Income Tax Risk

The computation of the Company's provision for income taxes is impacted by changes in tax legislation in Canada, the United States and the Caribbean. Any such changes could affect the Company's future earnings, cash flows, and financial position. The value of Emera's existing deferred income tax assets and liabilities are determined by existing tax laws and could be negatively impacted by changes in laws. Emera monitors the status of existing tax laws to ensure that changes impacting the Company are appropriately reflected in the Company's tax compliance filings and financial results.

## D. GUARANTEES AND LETTERS OF CREDIT

Emera has guarantees and letters of credit on behalf of third parties outstanding. The following significant guarantees and letters of credit are not included within the Consolidated Balance Sheets as at December 31, 2023:

TECO Energy has issued a guarantee in connection with SeaCoast's performance of obligations under a gas transportation precedent agreement. The guarantee is for a maximum potential amount of $45 million USD if SeaCoast fails to pay or perform under the contract. The guarantee expires five years after the gas transportation precedent agreement termination date, which was terminated on January 1, 2022. In the event that TECO Energy's and Emera's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's Investor Services ("Moody's") or S&P Global Ratings ("S&P"). TECO Energy would be required to provide its counterparty a letter of credit or cash deposit of $27 million USD.

TECO Energy issued a guarantee in connection with SeaCoast's performance obligations under a firm service agreement, which expires on December 31, 2055, subject to two extension terms at the option of the counterparty with a final expiration date of December 31, 2071. The guarantee is for a maximum potential amount of $13 million USD if SeaCoast fails to pay or perform under the firm service agreement. In the event that TECO Energy's long-term senior unsecured credit ratings are downgraded below investment grade by Moody's or S&P, TECO Energy would need to provide either a substitute guarantee from an affiliate with an investment grade credit rating or a letter of credit or cash deposit of $13 million USD.

Emera Inc. has issued a guarantee of $66 million USD relating to outstanding notes of ECI. This guarantee will automatically terminate on the date upon which the obligations have been repaid in full.

NSPI has issued guarantees on behalf of its subsidiary, NS Power Energy Marketing Incorporated, in the amount of $104 million USD (2022 – $119 million USD) with terms of varying lengths.

The Company has standby letters of credit and surety bonds in the amount of $103 million USD (December 31, 2022 – $145 million USD) to third parties that have extended credit to Emera and its subsidiaries. These letters of credit and surety bonds typically have a one-year term and are renewed annually as required.

Emera 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 2024. The amount committed as at December 31, 2023 was $56 million (December 31, 2022 – $63 million).

### Collaborative Arrangements

For the years ended December 31, 2023 and 2022, the Company has identified the following material collaborative arrangements:

Through NSPI, the Company is a participant in three wind energy projects in Nova Scotia. The percentage ownership of the wind project assets is based on the relative value of each party's project assets by the total project assets. NSPI has power purchase arrangements to purchase the entire net output of the projects and, therefore, NSPI's portion of the revenues are recorded net within regulated fuel for generation and purchased power. NSPI's portion of operating expenses is recorded in "OM&G" on the Consolidated Statements of Income. In 2023, NSPI recognized $8 million net expense (2022 – $12 million) in "Regulated fuel for generation and purchased power" and $3 million (2022 – $3 million) in "OM&G" on the Consolidated Statements of Income.

## 28. Cumulative Preferred Stock

### Authorized:

Unlimited number of First Preferred shares, issuable in series.

Unlimited number of Second Preferred shares, issuable in series.

| | | | **December 31, 2023** | | December 31, 2022 | |
|---|---|---|---|---|---|---|
| | Annual Dividend per Share | Redemption Price per Share | **Issued and Outstanding** | **Net Proceeds** | Issued and Outstanding | Net Proceeds |
| Series A | $ 0.5456 | $ 25.00 | **4,866,814** | **$ 119** | 4,866,814 | $ 119 |
| Series B | Floating | $ 25.00 | **1,133,186** | **$ 28** | 1,133,186 | $ 28 |
| Series C | $ 1.6085 | $ 25.00 | **10,000,000** | **$ 245** | 10,000,000 | $ 245 |
| Series E | $ 1.1250 | $ 25.00 | **5,000,000** | **$ 122** | 5,000,000 | $ 122 |
| Series F | $ 1.0505 | $ 25.00 | **8,000,000** | **$ 195** | 8,000,000 | $ 195 |
| Series H | $ 1.5810 | $ 25.00 | **12,000,000** | **$ 295** | 12,000,000 | $ 295 |
| Series J | $ 1.0625 | $ 25.00 | **8,000,000** | **$ 196** | 8,000,000 | $ 196 |
| Series L | $ 1.1500 | $ 26.00 | **9,000,000** | **$ 222** | 9,000,000 | $ 222 |
| Total | | | **58,000,000** | **$ 1,422** | 58,000,000 | $ 1,422 |

Characteristics of the First Preferred Shares:

| **First Preferred Shares** (1) (2) | Initial Yield (%) | Current Annual Dividend ($) | Minimum Reset Dividend Yield (%) | Earliest Redemption and/or Conversion Option Date | Redemption Value ($) | Right to Convert on a one for one basis |
|---|---|---|---|---|---|---|
| Fixed rate reset (3) (4) | | | | | | |
| Series A | 4.400 | 0.5456 | 1.84 | August 15, 2025 | 25.00 | Series B |
| Series C (5) (6) | 4.100 | 1.6085 | 2.65 | August 15, 2028 | 25.00 | Series D |
| Series F | 4.202 | 1.0505 | 2.63 | February 15, 2025 | 25.00 | Series G |
| Minimum rate reset (3) (4) | | | | | | |
| Series B | 2.393 | Floating | 1.84 | August 15, 2025 | 25.00 | Series A |
| Series H (5) (7) | 4.900 | 1.5810 | 4.90 | August 15, 2028 | 25.00 | Series I |
| Series J | 4.250 | 1.0625 | 4.25 | May 15, 2026 | 25.00 | Series K |
| Perpetual fixed rate | | | | | | |
| Series E (8) | 4.500 | 1.1250 | | | 25.00 | |
| Series L (9) | 4.600 | 1.1500 | | November 15, 2026 | 26.00 | |

(1) Holders are entitled to receive fixed or floating cumulative cash dividends when declared by the Board of Directors of the Corporation.
(2) On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding First Preferred Shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.
(3) On the redemption and/or conversion option date the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed or floating dividend rate, which for Series A, C, F and H is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield (Series H annual reset rate must be a minimum of 4.90 per cent) and for Series B equals the Government of Treasury Bill Rate on the applicable reset date, plus 1.84 per cent.
(4) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their Shares into an equal number of Cumulative Redeemable First Preferred Shares of a specified series. The Company has the right to redeem the outstanding Preferred Shares, Series D, Series G and Series I shares without the consent of the holder every five years thereafter for cash, in whole or in part at a price of $25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption and $25.50 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption in the case of redemptions on any other date after August 15, 2028, February 15, 2025 and August 15, 2028, respectively. The reset dividend yield for Series I equals the Government of Treasury Bill Rate on the applicable reset date, plus 2.54 per cent.
(5) On July 6, 2023, Emera announced it would not redeem the outstanding Preferred Shares, Series C and Series H on August 15, 2023. On August 4, 2023, Emera announced after having taken into account all conversion notices received from holders, no Series C Shares were converted into Series D Shares and no Series H Shares were converted into Series I shares.
(6) The annual fixed dividend per share for Series C Shares was reset from $1.1802 to $1.6085 for the five-year period from and including August 15, 2028.
(7) The annual fixed dividend per share for Series H Shares was reset from $1.2250 to $1.5810 for the five-year period from and including August 15, 2028.
(8) First Preferred Shares, Series E are redeemable at $25.00 per share.
(9) First Preferred Shares, Series L are redeemable at $26.00 on or after November 15, 2026 to November 15, 2027, decreasing $0.25 each year until November 15, 2030 and $25.00 per share thereafter.

First Preferred Shares are neither redeemable at the option of the shareholder nor have a mandatory redemption date. They are classified as equity and the associated dividends are deducted on the Consolidated Statements of Income before arriving at "Net income attributable to common shareholders" and shown on the Consolidated Statement of Changes in Equity as a deduction from retained earnings.

The First Preferred Shares of each series rank on a parity with the First Preferred Shares of every other series and are entitled to a preference over the Second Preferred Shares, the Common Shares, and any other shares ranking junior to the First Preferred Shares with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of the Company in the liquidation, dissolution or wind-up, whether voluntary or involuntary.

In the event the Company fails to pay, in aggregate, eight quarterly dividends on any series of the First Preferred Shares, the holders of the First Preferred Shares, for only so long as the dividends remain in arrears, will be entitled to attend any meeting of shareholders of the Company at which directors are to be elected and to vote for the election of two directors out of the total number of directors elected at any such meeting.

## 29. Non-Controlling Interest in Subsidiaries

| As at<br>millions of dollars | **December 31 2023** | December 31 2022 |
|---|---|---|
| Preferred shares of GBPC | **$ 14** | $ 14 |
| | **$ 14** | $ 14 |

### PREFERRED SHARES OF GBPC:

**Authorized:**

10,000 non-voting cumulative redeemable variable perpetual preferred shares.

| | 2023 | | 2022 | |
|---|---|---|---|---|
| **Issued and outstanding:** | **number of shares** | **millions of dollars** | number of shares | millions of dollars |
| Outstanding as at December 31 | **10,000** | **$ 14** | 10,000 | $ 14 |

### GBPC NON-VOTING CUMULATIVE VARIABLE PERPETUAL PREFERRED STOCK:

The preferred shares are redeemable by GBPC after June 17, 2021, at $1,000 Bahamian per share plus accrued and unpaid dividends and are entitled to a 6.0 per cent per annum fixed cumulative preferential dividend to be paid semi-annually.

The Preferred Shares rank behind GBPC's current and future secured and unsecured debt and ahead of all of GBPC's current and future common stock.

## 30. Supplementary Information to Consolidated Statements of Cash Flows

| For the<br>millions of dollars | Year ended December 31<br>**2023** | <br>2022 |
|---|---|---|
| Changes in non-cash working capital: | | |
| Inventory | **$ (31)** | $ (214) |
| Receivables and other current assets [(1)] | **653** | (636) |
| Accounts payable | **(538)** | 423 |
| Other current liabilities [(2)] | **(179)** | 193 |
| Total non-cash working capital | **$ (95)** | $ (234) |

(1) Includes $162 million related to the January 2023 settlement of NMGC gas hedges (2022 – ($162) million). Offsetting regulatory liability is included in operating cash flow before working capital resulting in no impact to net cash provided by operating activities.
(2) Includes ($166) million related to the Nova Scotia Cap-and-Trade program (2022 – $172 million). For further detail, refer to note 6. 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<br>millions of dollars | Year ended December 31<br>**2023** | <br>2022 |
|---|---|---|
| **Supplemental disclosure of cash paid:** | | |
| Interest | **$ 930** | $ 699 |
| Income taxes | **$ 43** | $ 67 |
| **Supplemental disclosure of non-cash activities:** | | |
| Common share dividends reinvested | **$ 271** | $ 237 |
| Decrease in accrued capital expenditures | **$ (19)** | $ (13) |
| Reclassification of short-term debt to long-term debt | **657** | – |
| Reclassification of long-term debt to short-term debt | **$ -** | $ 500 |
| **Supplemental disclosure of operating activities:** | | |
| Net change in short-term regulatory assets and liabilities | **$ 123** | $ (157) |

## 31. Stock-Based Compensation

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

Eligible employees may participate in the ECSPP. As of December 31, 2023, the plan allows employees to make cash contributions of a minimum of $25 to a maximum of $20,000 CAD or $15,000 USD per year for the purpose of purchasing common shares of Emera. The Company also contributes 20 per cent of the employees' contributions to the plan.

The plan allows reinvestment of dividends for all participants except where prohibited by law. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 7 million common shares. As at December 31, 2023, Emera was in compliance with this requirement.

Compensation cost for shares issued under the ECSPP for the year ended December 31, 2023 was $3 million (2022 – $3 million) and was included in "OM&G" on the Consolidated Statements of Income.

The Company also has a Common Shareholders DRIP, which provides an opportunity for shareholders residing in Canada to reinvest dividends and purchase common shares. This plan provides for a discount of up to 5 per cent from the average market price of Emera's common shares for common shares purchased in connection with the reinvestment of cash dividends. The discount was 2 per cent in 2023.

## STOCK-BASED COMPENSATION PLANS

### Stock Option Plan

The Company has a stock option plan that grants options to senior management of the Company for a maximum term of 10 years. The option price of the stock options is the closing price of the Company's common shares on the Toronto Stock Exchange on the last business day on which such shares were traded before the date on which the option is granted. The maximum aggregate number of shares issuable under this plan is 14.7 million shares. As at December 31, 2023, Emera was in compliance with this requirement.

Stock options granted in 2021 and prior vest in 25 per cent increments on the first, second, third and fourth anniversaries of the date of the grant. Stock options granted in 2022 and thereafter vest in 20 per cent increments on the first, second, third, fourth and fifth anniversaries of the date of the grant. If an option is not exercised within 10 years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The total number of stocks to be optioned to any optionee shall not exceed five per cent of the issued and outstanding common stocks on the date the option is granted.

For stock options granted in 2021 and prior, unless a stock option has expired, vested options may be exercised within the 27 months following the option holder's date of retirement, six months following a termination without just cause or death, and within sixty days following the date of termination for just cause or resignation. Commencing with the 2022 stock option grant, vested options may be exercised during the full term of the option following the option holders date of retirement, six months following a termination without just cause or death, and within sixty days following the date of termination for just cause or resignation. If stock options are not exercised within such time, they expire.

The Company uses the Black-Scholes valuation model to estimate the compensation expense related to its stock-based compensation and recognizes the expense over the vesting period on a straight-line basis.

The following table shows the weighted average FV per stock option along with the assumptions incorporated into the valuation models for options granted, for the year-ended December 31:

| | **2023** | 2022 |
|---|---|---|
| Weighted average FV per option | **$ 6.32** | $ 5.35 |
| Expected term (1) | **5 years** | 5 years |
| Risk-free interest rate (2) | **3.53%** | 1.79% |
| Expected dividend yield (3) | **5.05%** | 4.55% |
| Expected volatility (4) | **20.07%** | 18.87% |

(1) The expected term of the option awards is calculated based on historical exercise behaviour and represents the period of time that the options are expected to be outstanding.
(2) Based on the Bank of Canada five-year government bond yields.
(3) Incorporates current dividend rates and historical dividend increase patterns.
(4) Estimated using the five-year historical volatility.

The following table summarizes stock option information for 2023:

| | Total Options | | Non-Vested Options (1) | |
|---|---|---|---|---|
| | Number of Options | Weighted average exercise price per share | Number of Options | Weighted average grant date fair-value |
| Outstanding as at December 31, 2022 | 2,853,879 | $ 50.41 | 1,348,400 | $ 4.08 |
| Granted | 483,100 | 54.64 | 483,100 | 6.32 |
| Exercised | (146,475) | 43.94 | N/A | N/A |
| Forfeited | (94,900) | 56.32 | (51,625) | 3.61 |
| Vested | N/A | N/A | (526,620) | 3.58 |
| **Options outstanding December 31, 2023** | **3,095,604** | **$ 51.20** | **1,253,255** | **$ 5.17** |
| **Options exercisable December 31, 2023** (2) (3) | **1,842,349** | **$ 48.39** | | |

(1) As at December 31, 2023, there was $5 million of unrecognized compensation related to stock options not yet vested which is expected to be recognized over a weighted average period of approximately 3 years (2022 – $4 million, 3 years).
(2) As at December 31, 2023, the weighted average remaining term of vested options was 5 years with an aggregate intrinsic value of $8 million (2022 – 5 years, $10 million).
(3) As at December 31, 2023, the FV of options that vested in the year was $2 million (2022 – $2 million).

Compensation cost recognized for stock options for the year ended December 31, 2023 was $2 million (2022 – $2 million), which was included in "OM&G" on the Consolidated Statements of Income.

As at December 31, 2023, cash received from option exercises was $6 million (2022 – $9 million). The total intrinsic value of options exercised for the year ended December 31, 2023 was $2 million (2022 – $4 million). The range of exercise prices for the options outstanding as at December 31, 2023 was $32.35 to $60.03 (2022 – $32.35 to $60.03).

## SHARE UNIT PLANS

The Company has DSU, PSU and RSU plans. The plans and the liabilities are marked-to-market at the end of each period based on an average common share price at the end of the period.

### Deferred Share Unit Plans

Under the Directors' DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation, subject to requirements to receive a minimum portion of their annual retainer in DSUs. Directors' fees are paid on a quarterly basis and, at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera's common shares, the Director's DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan. Following retirement or resignation from the Board, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by Emera's closing common share price on the date DSUs are redeemed.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50 per cent of the value of their actual annual incentive award (25 per cent in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When short-term incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Payments are made in cash.

In addition, special DSU awards may be made from time to time by the Management Resources and Compensation Committee ("MRCC"), to selected executives and senior management to recognize singular achievements or by achieving certain corporate objectives.

A summary of the activity related to employee and director DSUs for the year ended December 31, 2023 is presented in the following table:

| | Employee DSU | Weighted Average Grant Date FV | Director DSU | Weighted Average Grant Date FV |
|---|---|---|---|---|
| Outstanding as at December 31, 2022 | 627,223 | $ 41.55 | 664,258 | $ 45.83 |
| Granted including DRIP | 85,740 | 47.66 | 117,893 | 49.99 |
| Exercised | N/A | N/A | (53,093) | 49.39 |
| **Outstanding and exercisable as at December 31, 2023** | **712,963** | **$ 42.29** | **729,058** | **$ 46.24** |

Compensation cost recovery recognized for employee and director DSU's for the year ended December 31, 2023 was $2 million (2022 – $6 million). Tax expense related to this compensation cost recovery for share units realized for the year ended December 31, 2023 was $1 million (2022 – $2 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2023 for employees was $36 million (2022 – $33 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2023 for directors was $37 million (2022 – $34 million). Cash payments made during the year ended December 31, 2023 associated with the DSU plan were $3 million (2022 – $8 million).

### Performance Share Unit Plan

Under the PSU plan, certain executive and senior employees are eligible for long-term incentives payable through the plan. PSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional PSUs. The PSU value varies according to the Emera common share market price and corporate performance.

PSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios. In the case of retirement, as defined in the PSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee PSUs for the year ended December 31, 2023 is presented in the following table:

| | Employee PSU | Weighted Average Grant Date FV | Aggregate intrinsic value |
|---|---|---|---|
| Outstanding as at December 31, 2022 | 690,446 | $ 56.24 | $ 40 |
| Granted including DRIP | 386,261 | 52.71 | |
| Exercised | (323,155) | 54.62 | |
| Forfeited | (10,187) | 55.15 | |
| **Outstanding as at December 31, 2023** | **743,365** | **$ 55.13** | **$ 41** |

Compensation cost recognized for the PSU plan for the year ended December 31, 2023 was $11 million (2022 – $18 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2023 were $3 million (2022 – $5 million). Cash payments made during the year ended December 31, 2023 associated with the PSU plan were $19 million (2022 – $24 million).

### Restricted Share Unit Plan

Under the RSU plan, certain executive and senior employees are eligible for long-term incentives payable through the plan. RSUs are granted annually for three-year overlapping performance cycles, resulting in a cash payment. RSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to the effective grant date. Dividend equivalents are awarded and paid in the form of additional RSUs. The RSU value varies according to the Emera common share market price.

RSUs vest at the end of the three-year cycle and the payouts will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and may be pro-rated in certain departure scenarios. In the case of retirement, as defined in the RSU plan, grants may continue to vest in full and payout in normal course post-retirement.

A summary of the activity related to employee RSUs for the year ended December 31, 2023 is presented in the following table:

| | Employee RSU | Weighted Average Grant Date FV | Aggregate intrinsic value |
|---|---|---|---|
| Outstanding as at December 31, 2022 | 508,468 | $ 56.25 | $ 30 |
| Granted including DRIP | 236,537 | 52.07 | |
| Exercised | (171,537) | 54.62 | |
| Forfeited | (10,827) | 54.76 | |
| **Outstanding as at December 31, 2023** | **562,641** | **$ 55.01** | **$ 32** |

Compensation cost recognized for the RSU plan for the year ended December 31, 2023 was $10 million (2022 – $9 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2023 were $3 million (2022 – $2 million). Cash payments made during the year ended December 31, 2023 associated with the RSU plan were $10 million (2022– nil).

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

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

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

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

| As at | **December 31, 2023** | | December 31, 2022 | |
|---|---|---|---|---|
| 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) | **$ 489** | **$ 6** | $ 501 | $ 6 |

## 33. Subsequent Events

These financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 26, 2024, the date the financial statements were issued.

# Emera Leadership and Board

As of March 31, 2024

## Emera Leadership

**Scott Balfour**
President and
Chief Executive Officer,
Emera Inc.

**Mike Barrett**
Executive Vice President,
Legal and General Counsel,
Emera Inc.

**Greg Blunden**
Chief Financial Officer,
Emera Inc.

**Archie Collins**
President and Chief
Executive Officer,
Tampa Electric

**Peter Gregg**
President and Chief
Executive Officer,
Nova Scotia Power

**Karen Hutt**
Executive Vice President,
Business Development
and Strategy,
Emera Inc.

**Bruce Marchand**
Chief Risk and Sustainability
Officer,
Emera Inc.

**Dan Muldoon**
Executive Vice President,
Project Development
and Operations Support,
Emera Inc.

**Michael Roberts**
Chief Human Resources
Officer,
Emera Inc.

**Ryan Shell**
President,
New Mexico Gas Company

**Judy Steele**
President and
Chief Operating Officer,
Emera Energy

**Helen Wesley**
President,
Peoples Gas

## Board of Directors

**Jackie Sheppard**
Chair, Emera Board of
Directors
Calgary, Alberta

**Scott Balfour**
President and
Chief Executive Officer
Halifax, Nova Scotia

**James Bertram**
Calgary, Alberta

**Henry Demone**
Lunenburg, Nova Scotia

**Paula Gold-Williams**
San Antonio, Texas

**Kent Harvey**
New York, New York

**Lynn Loewen**
Westmount, Quebec

**Brian Porter**
Toronto, Ontario

**Ian Robertson**
Oakville, Ontario

**Andrea Rosen**
Toronto, Ontario

**Karen Sheriff**
Picton, Ontario

**Jochen Tilk**
Toronto, Ontario

# Shareholder Information

For general inquiries, please contact our corporate office:

**Emera Inc.**
P.O. Box 910
Halifax, Nova Scotia B3J 2W5
T: 902.450.0507 or 1.888.450.0507

Information regarding Company news and initiatives, including our 2023 Annual Report, is available on our website:
**www.emera.com**

## Transfer Agent

TSX Trust Company
P.O. Box 2082, Station C
Halifax, Nova Scotia B3J 3B7
T: 1.877.982.8762
F: 1.888.249.6189
**www.tsxtrust.com**

## Investor Services

T: 902.428.6060 or 1.800.358.1995
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**E: investors@emera.com**

## Financial Analysts, Portfolio Managers and Institutional Investors

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This Annual Report contains forward-looking information. Actual future results may differ materially. Additional financial and operational information is filed electronically with various securities commissions in Canada, copies of which are available electronically under Emera's profile on SEDAR+ at **www.sedarplus.ca**.

## Share Listings

Toronto Stock Exchange (TSX)
Common shares: EMA
Preferred shares: EMA.PR.A, EMA.PR.B, EMA.PR.C, EMA.PR.E, EMA.PR.F, EMA.PR.H, EMA.PR.J and EMA.PR.L
Barbados Stock Exchange (BSE)
Depositary receipts: EMABDR
Bahamas International Securities Exchange (BISX)
Depositary receipts: EMAB

## Shares Outstanding

Common shares: 284,117,511
(as of December 31, 2023)

## Dividends Paid in 2023

Emera Inc. paid common share dividends of $0.69 per quarter in Q1, Q2 and Q3 (annualized rate of $2.76 per common share) and $0.7175 in Q4 (annualized rate of $2.87 per common share), for an effective annual common share dividend rate of $2.7875 per common share.

## Dividend Payments in 2024

Subject to approval by the Board of Directors, dividends for Emera Inc. are payable on or about the 15th of February, May, August and November. A first quarter common share dividend of $0.7175, a Series A First Preferred Share dividend of $0.1364, a Series B First Preferred Share dividend of $0.4408, a Series C First Preferred Share dividend of $0.40213, a Series E First Preferred Share dividend of $0.28125, a Series F First Preferred Share dividend of $0.26263, a Series H First Preferred Share dividend of $0.39525, a Series J First Preferred Share dividend of $0.265625 and a Series L First Preferred Share dividend of $0.2875 were declared and paid on February 15, 2024.

## Dividend Reinvestment and Share Purchase Plan

Emera's Dividend Reinvestment and Share Purchase Plan is available to shareholders who reside in Canada. The plan provides a convenient and economical means of acquiring additional common shares through the reinvestment of dividends with a discount of up to five per cent. In 2023, the discount was two per cent. Plan participants may also contribute cash payments of up to $5,000 per quarter. Plan participants pay no commissions, service charges or brokerage fees for shares purchased under the plan. Please contact Investor Services if you have questions or wish to receive an enrollment form.

## Direct Deposit Service

Registered shareholders may have dividends deposited directly to any bank account in Canada. To arrange this service, please contact TSX Trust Company. Beneficial shareholders should contact their financial intermediary.

## Quarterly Earnings

Quarterly earnings are expected to be announced in May, August and November 2024. Year-end results for 2024 will be released in February 2025.

Emera is represented in the TSX Composite, TSX Capped Utilities, TSX60 and select MSCI and FTSE World indexes.

# Our Operating Companies

As of December 31, 2023

**TAMPA ELECTRIC**

Vertically integrated electric utility serving about 840,000 customers in west central Florida.

**NOVA SCOTIA POWER**

Vertically integrated electric utility serving approximately 549,000 customers in Nova Scotia.

**PEOPLES GAS**

Natural gas utility serving 490,000 customers in Florida.

**NEW MEXICO GAS**

Natural gas utility serving 540,000 customers in New Mexico.

**EMERA CARIBBEAN**

Vertically integrated electric utilities serving more than 150,000 customers on the islands of Barbados and Grand Bahama.

**EMERA NEWFOUNDLAND & LABRADOR**

Owns and operates the Maritime Link and manages Emera's investment in an associated project.

**EMERA ENERGY**

Energy marketing and trading, asset management and optimization in Canada and the US.

**EMERA NEW BRUNSWICK**

Owns and operates the Brunswick pipeline, a 145-kilometre natural gas pipeline in New Brunswick.

**BLOCK ENERGY**

A technology company focused on finding new, innovative ways to deliver renewable and resilient energy to customers.

Emera

www.emera.com