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June 20, 2022

Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

Please find enclosed five (5) copies of Maritime Electric's General Rate Application and Evidence for approval of a revised schedule of rates, tolls and charges for the periods March 1, 2023 to February 29, 2024, March 1, 2024 to February 28, 2025 and March 1, 2025 to February 28, 2026. An electronic copy will be forwarded shortly.

If you require further information, please do not hesitate to contact me at (902) 629-3701.

Yours truly,

MARITIME ELECTRIC

T. Michelle Francis
Vice President,
Finance & Chief Financial Officer

MF30
Encl. as noted

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE

ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Sections 10, 13(1) and 20 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the years March 1, 2023 to February 28, 2026 and for certain approvals incidental to such an order.

APPLICATION AND EVIDENCE

OF

MARITIME ELECTRIC COMPANY, LIMITED

June 20, 2022

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C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE
ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Sections 10, 13(1) and 20 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the years March 1, 2023 to February 28, 2026 and for certain approvals incidental to such an order.

<u>Introduction</u>

Maritime Electric Company, Limited ("Maritime Electric" or the "Company") is a public utility subject to the *Electric Power Act* engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

<u>Application</u>

Maritime Electric hereby applies for an order of the Island Regulatory and Appeals Commission ("IRAC" or the "Commission") approving rates, tolls and charges for electric service for the years March 1, 2023 to February 28, 2026 as set out in Appendix A and certain other approvals incidental thereto. Maritime Electric proposes adjustments to both the base rate and rate adjustment per kilowatt hour ("kWh") contained in the Energy Cost Adjustment Mechanism ("ECAM") calculation to reflect changes in forecast energy-related costs. The Company is also requesting confirmation of its average common equity and approval of the proposed return on average common equity from the Commission in respect of the fiscal years 2023, 2024 and 2025.

The proposals contained in this Application represent a just and reasonable balance of the interests of Maritime Electric and those of its customers and will, if approved, allow the Company to continue to provide a high level of service at prices that are, in all circumstances, reasonable.

<u>Procedure</u>

Filed herewith is the Affidavit of Jason C. Roberts, T. Michelle Francis, Angus S. Orford and Enrique A. Riveroll, which contains the evidence on which Maritime Electric relies in this Application.

Dated at Charlottetown, Province of Prince Edward Island, this 20th day of June, 2022.

D. Spencer Campbell, Q.C.

STEWART MCKELVEY
65 Grafton Street, PO Box 2140
Charlottetown PE C1A 8B9
Telephone: 902-629-4549
Facsimile: 902-892-2485
Solicitors for Maritime Electric Company, Limited

2.0 AFFIDAVIT

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Sections 10, 13(1) and 20 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the years March 1, 2023 to February 28, 2026 and for certain approvals incidental to such an order.

AFFIDAVIT

We, Jason Christopher Roberts of Suffolk, T. Michelle Francis of Emyvale, Angus Sumner Orford of Charlottetown and Enrique Alfonso Riveroll of New Dominion, in Queens County, Province of Prince Edward Island, MAKE OATH AND SAY AS FOLLOWS:

We are the President and Chief Executive Officer, Vice President, Finance and Chief Financial Officer, Vice President, Corporate Planning and Energy Supply and Vice President, Customer Service, respectively, for Maritime Electric and as such have personal knowledge of the matters deposed to herein, except where noted, in which case we rely upon the information of others and in which case we verily believe such information to be true.

Maritime Electric is a public utility subject to the provisions of the *Electric Power Act* engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

We prepared or supervised the preparation of the evidence and to the best of our knowledge and belief the evidence is true in substance and in fact. A copy of the evidence is attached to this our Affidavit, and is collectively known as Exhibit A, contained at Tabs 3 through 7 inclusive.

The evidence found at Tab 3 (the "Introduction") contains a brief overview of Maritime Electric and a summary of the impact of the proposals on customer electricity costs.

The evidence found at Tab 4 (the "Customer Operations") contains information on how Maritime Electric serves its customers along with the Company's energy sales forecast.

The evidence found at Tab 5 (the "Cost of Service and Projections") outlines the cost to deliver the forecast energy to customers, including the Company's proposed costs of capital. This section also contains information on the forecast of regulatory deferral accounts.

The evidence found at Tab 6 (the "Rate Base and Revenue Requirement") provides an overview of the Company's rate base and revenue requirement for the rate-setting period.

The evidence found at Tab 7 (the "Customer Rates") illustrates the impact of the proposals in the Company's Application on a cross section of Customers' annual costs in the residential and commercial rate classes.

Tab 8 contains a proposed Order of the Commission based on the Company's Application.

The evidence found at Tab 9 (the "Appendices") contains Appendix A through I inclusive which are referred to in the evidence.

SECTION 2.0 - AFFIDAVIT

SWORN TO SEVERALLY at Charlottetown, Prince Edward Island, the 20th day of June, 2022. Before me:

Jason C. Roberts

T. Michelle Francis

Angus S. Orford

Enrique A. Riveroll

A Commissioner for taking affidavits in the Supreme Court of Prince Edward Island.

3.0 INTRODUCTION

3.1 Application Background

3.1.1 About Maritime Electric

Maritime Electric owns and operates a fully integrated system providing for the purchase, generation, transmission, distribution and sale of electricity throughout Prince Edward Island ("PEI"). The Company's head office is located in Charlottetown with generating facilities in Charlottetown and Borden-Carleton.

Maritime Electric is the primary provider of electricity on PEI, delivering approximately 90 per cent of the energy supplied on PEI. To meet customers' energy demand and supply requirements, the Company has contractual entitlement to capacity and energy from NB Power's Point Lepreau Nuclear Generating Station ("Point Lepreau") and an agreement for the purchase of capacity and system energy from NB Power delivered via four submarine cables owned by the Province of PEI.[1] Through various contracts with the PEI Energy Corporation ("PEIEC"), the Company purchases the capacity and energy from 92.5 megawatts ("MW") of wind generation on PEI.

Maritime Electric is a public utility subject to the *Electric Power Act*. As a public utility, the Company is subject to regulatory oversight and approvals of IRAC, whose jurisdiction to regulate public utilities is found in the *Electric Power Act* and the *Island Regulatory and Appeals Commission Act*.

3.1.2 Balancing Cost and Service

Maritime Electric is responsible for delivering approximately 90 per cent of the energy supplied on PEI. The Company manages its operations in a manner responsive to customers' service expectations.

[1] The Energy Purchase Agreement is between Maritime Electric and New Brunswick Energy Marketing.

Efficient utility operations is consistent with the *Electric Power Act*, which requires Maritime Electric to manage its operations in an efficient manner that results in power being delivered to customer at a reasonable cost.[2]

Reliable service delivery and appropriate cost management are therefore foundational to the Company's operations.

3.1.3 Maritime Electric's Performance

Maritime Electric's customers have indicated a reasonable level of satisfaction with the Company's service.

The reliability of the electrical system is critical to maintaining and increasing customer satisfaction. The average duration of customer outages excluding the impact of major storm events has been on par with the Canadian average. However, including the impact of major storm events, the average duration of customer outages has been generally lower than the Canadian average.

The Company's operations are focused on maintaining overall levels of service reliability for customers. Maritime Electric maintains the reliability of its service delivery through a combination of routine inspections and maintenance, stable and predictable capital investments, and a timely response to customer outages.

3.1.4 Provincial Electricity Sector Developments

In February 2022, the Provincial Government released its 2040 Net Zero Framework ("Net Zero Report") which summarizes its plan to achieve net zero energy by 2030 and net zero greenhouse gas ("GHG") emissions by 2040.[3] A number of elements in the Net Zero Report will impact the provision of electricity service on PEI.

First, the Net Zero Report plans to reduce Islanders reliance on fossil fuels to heat their homes and power their vehicles. The alternative is that Islanders will rely more on electricity to heat their

2 Page 5 of the *Electric Power Act*.

3 Net zero energy refers to producing no more GHG emissions from energy use than PEI land, ocean and technologies can absorb. Net zero GHG emissions refers to producing no more GHG emission from all sources than PEI land, ocean and technologies can absorb.

homes and power their vehicles. This is expected to increase demand for electricity and that electricity be available when needed. In addition, the electrical system will need to be enhanced to accommodate this increased demand.

Second, the Net Zero Report plans to evaluate and invest in ways to convert various types of waste into clean energy that can be then used to heat homes and power vehicles. Maritime Electric will be required to play a role in distributing this energy source to its customers.

Finally, the Net Zero Report identifies carbon pricing as a cost-effective mechanism to drive investments towards cleaner, more efficient alternatives, such as electricity. This carbon price signal is expected to accelerate the increased demand for electricity.

The assumptions and inputs used in this General Rate Application ("GRA" or "Application") have not been influenced by the Net Zero Report. As this Application covers the period of 2023 to 2025 (the "rate-setting period"), it is not expected that the initiatives identified in the Net Zero Report will result in a noticeable incremental impact on electricity demand during the rate-setting period. However, analyses and actions must begin now to ensure the Net Zero Report goals and objectives can be achieved.

The Net Zero Report will influence Maritime Electric's long-term planning of the electrical system. The impact of Islanders transitioning to electricity to heat their homes and power their vehicles has a transformational impact on the electrical system. As the impact on the demand for electricity is realized, the Company's Integrated System Plans will address the investment required to accommodate the increased demand for electricity.

3.1.5 Risk and Return

In this Application, the Commission will consider an appropriate capital structure for ratemaking purposes including an appropriate return on common equity ("ROE") invested in the Company.

Expert evidence filed with this Application indicates that Maritime Electric has above-average business risk in comparison to other Canadian utilities, and its risk warrants a higher return. Maritime Electric's business risks continue to be defined by longstanding factors, including its small size, lack of geographic diversity, economic conditions on PEI, operating risks associated with major weather events, and government policy uncertainty.

3.2 Application Proposals

The maintenance of Maritime Electric's financial integrity is necessary to enable the delivery of safe and reliable electrical service to customers over the long term. Prudent financial management benefits both the Company and its customers.

Maritime Electric's financial management has enabled the Company to maintain its financial integrity over time. The proposals in this Application are consistent with maintaining the Company's financial integrity through to 2025 and are consistent with the fair return standard.[4]

3.2.1 Revenue Requirements

In this Application, Maritime Electric's revenue requirement is forecast to increase by an average of 4.9 per cent per year during the rate-setting period.[5] This increase in revenue requirement necessitates a proposed average increase in current customer costs of approximately 3.0 per cent per year during the rate-setting period.[6]

As illustrated in Chart 3-1, over 80 per cent of this rate increase is the result of four primary changes in the Company's cost of service: (i) energy-related costs; (ii) depreciation; (iii) return; and (iv) operating costs.[7]

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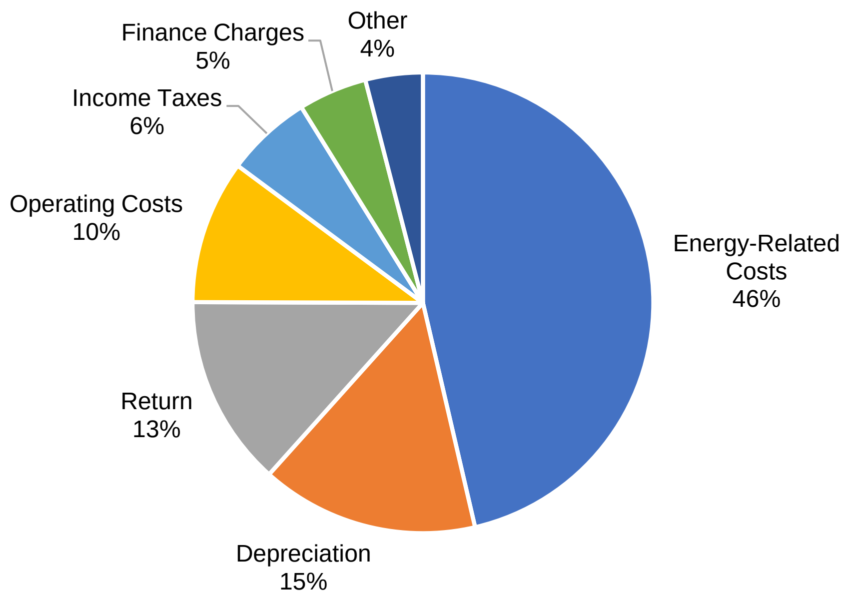
[4] The fair return standard is discussed further in Section 5.2.1 of this Application.
[5] Refer to Table 6-5 in Section 6.3.1 of this Application.
[6] Rate increase is based on a selected benchmark consumption, as shown in Tables 7-4, 7-5 and 7-6 in Section 7.3 of this Application.
[7] Chart 3-1 is based on the Company's revenue requirement for the rate-setting period before considering the impact of other revenue, which reduces the revenue requirement to be recovered from customers.

CHART 3-1
Breakdown of Increase in Average Customer Cost of Electricity
2023-2025



Energy-related costs account for 46 per cent of the proposed rate increase. As discussed in Section 5.1.1 of this Application, the increase in energy-related costs is driven by: (i) forecast sales growth requiring an increase in energy supply; and (ii) a projected recoverable ECAM balance at the end of 2022 of $6.8 million primarily due to a scheduled outage at Point Lepreau in 2022.

Depreciation accounts for 15 per cent of the proposed rate increase. As discussed in Section 5.1.5 of this Application, depreciation and amortization reflects: (i) the adoption of all of the 2020 Depreciation Study recommendations; (ii) amortization of accumulated reserve variance associated with the Charlottetown Thermal Generating Station (“CTGS”) (the “CTGS reserve variance”) over five years; and (iii) continued investment in the electrical system.

Return on common equity of 9.95 per cent accounts for 13 per cent of the proposed rate increase. As discussed in Section 5.2 of this Application, expert evidence indicates a fair return for Maritime Electric for 2023 to 2025 comprises: (i) a capital structure consisting of 40 per cent common equity and 60 per cent debt; and (ii) a ROE of 9.95 per cent. A 40 per cent common equity component and a ROE of 9.95 per cent is consistent with maintaining Maritime Electric's financial integrity and the fair return standard.

Operating costs account for 10 per cent of the proposed rate increase. As discussed in Sections 5.1.2 and 5.1.3 of this Application, operating costs are generally forecast to increase between 2.5 and 3.0 per cent annually during the rate-setting period, with the exception of select areas where circumstances justify a higher increase. One such area is vegetation management. Evidence is provided in Appendix E to support an expanded vegetation management program.

3.2.2 Customer Rates, Rules and Regulations

Maritime Electric is required under the terms of the *Electric Power Act* to file with the Commission a schedule of rates, tolls and charges whenever the utility wishes to vary those rates, tolls or charges.[8] The Company's currently approved General Rules and Regulations were filed with the Commission on February 25, 2022 for rates effective March 1, 2022 and approved by the Commission in Order UE22-01. Until modified, altered or amended, these General Rules and Regulations remain in effect as filed.

The proposals set forth in this Application solely relate to increases to the energy charges per kWh of all customer classes. The Company is not proposing any changes to the monthly service charges or demand charges for applicable customer classes. Neither is the Company proposing any updates to the terms and conditions for the provision of services or ancillary charges to customers of the Company in this Application.

The proposed changes to the energy charge per kWh include changes to the basic energy charge per kWh, which is designed to recover the Company's annual revenue requirement, and to rate riders, which are designed to collect or refund amounts owing to or from Maritime Electric or a third-party.

[8] Section 20 (1) of the *Electric Power Act.*

The details of these proposed components to rates is provided in Section 7.2 and a comprehensive schedule of existing customer rates effective March 1, 2022 and proposed customer rates by class for March 1, 2023, March 1, 2024 and March 1, 2025 are provided in Appendix A.

A summary of the cumulative customer rates (i.e., including the basic energy charge and rate riders) for the four principal customer classes is provided in Table 3-1.

TABLE 3-1
Total Energy Charge ($/kWh, except %)
Effective March 1

Rate Class	Approved 2022	Proposed 2023	Proposed 2024	Proposed 2025	Cumulative Variance over 2022 Rates	Average Annual Variance
Residential - First Block	0.1532	0.1592	0.1652	0.1715	11.9%	4.0%
Residential - Second Block	0.1228	0.1265	0.1313	0.1362	10.9%	3.6%
General Service - First Block	0.1871	0.1956	0.2030	0.2107	12.6%	4.2%
General Service - Second Block	0.1241	0.1279	0.1328	0.1377	10.9%	3.6%
Small Industrial - First Block	0.1834	0.1916	0.1988	0.2064	12.5%	4.2%
Small Industrial - Second Block	0.0950	0.0967	0.1004	0.1040	9.4%	3.1%
Large Industrial	0.0780	0.0808	0.0837	0.0867	11.1%	3.7%

As previously indicated, the Company is not proposing to change the monthly service charge or demand charges. As a result, the change in the total annual cost per customer will be less than the total change in the per kWh rate depending on their energy usage. Table 3-2 provides a benchmark of the increase in annual costs that will be experienced by residential and general service customers.

TABLE 3-2
Annual Cost for Select Benchmark Customers
March 1 to February 28

	Approved	Proposed		
	2022/2023	**2023/2024**	**2024/2025**	**2025/2026**
Rural Residential[9]	$ 1,625.02	$ 1,673.33	$ 1,722.58	$ 1,773.91
Annual Increase	**2.0%**[10]	**3.0%**	**2.9%**	**3.0%**
Urban Residential[11]	$ 1,592.22	$ 1,640.90	$ 1,690.15	$ 1,741.48
Annual Increase	**2.0%**[8]	**3.1%**	**3.0%**	**3.0%**
General Service[12]	$ 27,351.95	$ 28,185.25	$ 29,036.34	$ 29,902.00
Annual Increase	**2.0%**[8]	**3.0%**	**3.0%**	**3.0%**

The detailed bill calculations to support the amounts in Table 3-2 are provided in Section 7.3.

[9] Based on a benchmark energy consumption of 650 kWh per month or 7,800 kWh per year.
[10] Rate increase approved per Order UE22-01.
[11] Based on a benchmark energy consumption of 650 kWh per month or 7,800 kWh per year.
[12] Based on a benchmark energy consumption of 10,000 kWh and 50 KW per month or 120,000 kWh and 600 KW per year.

4.0 CUSTOMER OPERATIONS

4.1 Customer Service

4.1.1 Customer Service Delivery

Maritime Electric expects to serve approximately 89,600 customers by 2023, an increase of approximately 3.8 per cent from 2021.[13]

Customers primarily contact the Company to obtain account information, make payment arrangements, report or enquire about outages, request new services or field work. Delivering responsive customer service requires effectively managing customers' interactions.

Table 4-1 provides the number of customer enquiries received by phone and email annually from 2017 to 2021.

TABLE 4-1
Number of Customer Enquires

Type of Interaction	2017	2018	2019	2020	2021
Phone - inbound	84,964	92,828	80,902	70,683	80,678
Email[14]	-	4,406	6,915	19,830	20,221

While phone and email are currently the primary forms of customer enquiries, there are other means by which customers can contact the Company, such as in-person appointments. The Company's website continues to be enhanced to offer more self-serve options, and in 2020 web chat was introduced on a limited basis.[15] Maritime Electric now has more options than ever for customers to interact with the Company.

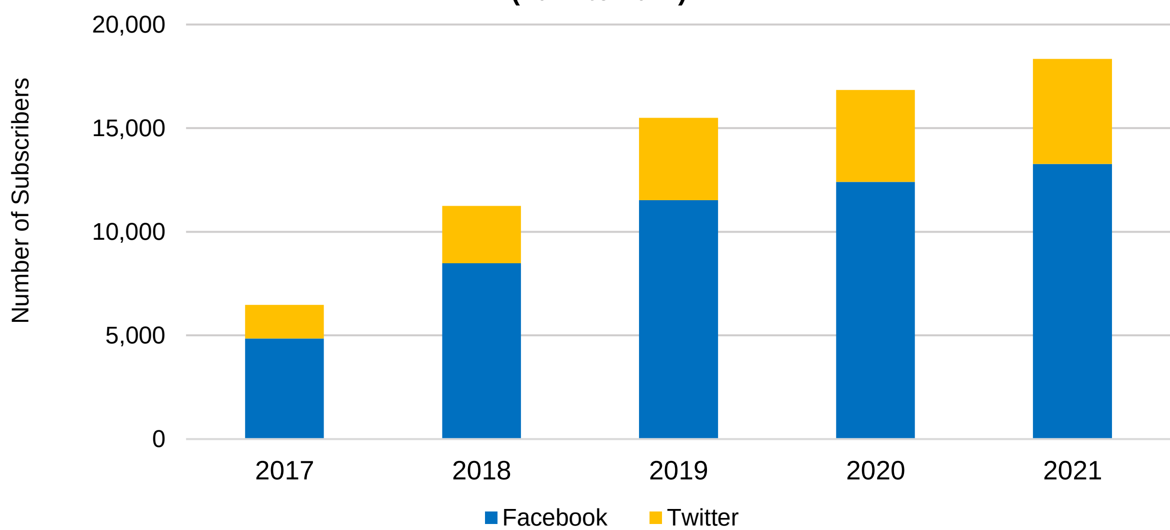
In 2018 Maritime Electric significantly enhanced its website. The enhanced website was developed to provide customers with greater functionality while accessing the website using their mobile devices. In addition, a new outage map was launched in 2018 that provides real-time

13 At December 31, 2021, the Company had 86,335 customers.
14 Tracking of all email interactions was implemented in February 2020, prior to which only limited tracking was available.
15 Web chat is an online function that allows customers to communicate directly with a Customer Service Representative via the website.

information on where outages are located and how many customers are affected. The website now offers a self-serve option for customers to report outages, including a customer self-service portal called MyPower. Customers can access MyPower at any time to view their bills, payments and consumption, manage multiple accounts, track the status of a service request, and signup for electronic billing (i.e., paperless billing).

Maritime Electric continues to use social media to share information with its customers, including information on electrical safety, outages, energy conservation tips, contests and promotions, and available programs and services. Chart 4-1 shows the number of subscribers to Maritime Electric's social media channels since 2017.[16]

CHART 4-1
Social Media Subscribers
(2017 to 2021)



Since 2017, the number of subscribers to the Company's social media channels has nearly tripled.[17] Combined, the Company's Facebook and Twitter accounts had over 18,000 subscribers in 2021. Customers' increased use of social media is consistent with their growing preference for digital communications.

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[16] Maritime Electric also uses LinkedIn. Historical information on LinkedIn subscribers is not available, therefore it was not included in the table provided.

[17] 6,468 subscribers in 2017 compared to 18,334 subscribers in 2021 (18,334 / 6,468 = 2.8).

4.1.2 Customer Service Efficiency

Maritime Electric continues to invest in technology-driven initiatives to improve the quality of service for customers. The Company balances the cost of the initiatives with efficiency gains and delivery of service.

In 2019 Maritime Electric replaced the Company's outdated and operationally inadequate phone system with a Virtual Contact Centre ("VCC"). The VCC is a private, cloud-based all-in-one software platform that enables unified communications and provides training and data collection for quality control, call monitoring and tracking.[18] The transition to the VCC also offered cost savings of approximately 80 per cent in the annual cost of toll-free numbers in 2020 compared to 2018.[19]

The VCC provides enhanced customer interactions by allowing customers to leave a voicemail and/or callback number during times of high call volume, such as during a power outage. The VCC also improved contingency planning during after-hour outage events allowing Customer Service Representatives ("CSRs") to log in from home and safely serve customers approximately 10 to 20 minutes faster. The VCC also allowed for a safe and seamless transition to CSRs working from home during the pandemic.

Maritime Electric manages approximately 900,000 bills and payments annually. Currently more than 90 per cent of customer payment methods are electronic deposit or pre-authorized payments. Approximately 58 per cent of the Company's customers have opted for paperless billing. This represents a cumulative savings of approximately $640,000.[20]

4.1.3 Customer Satisfaction

Maritime Electric is responsible for delivering approximately 90 per cent of the energy supplied on PEI. The Company manages its operations in a manner responsive to customers' service expectations.

18 Unified communications is a framework for integrating various forms of communication to improve collaboration and productivity.

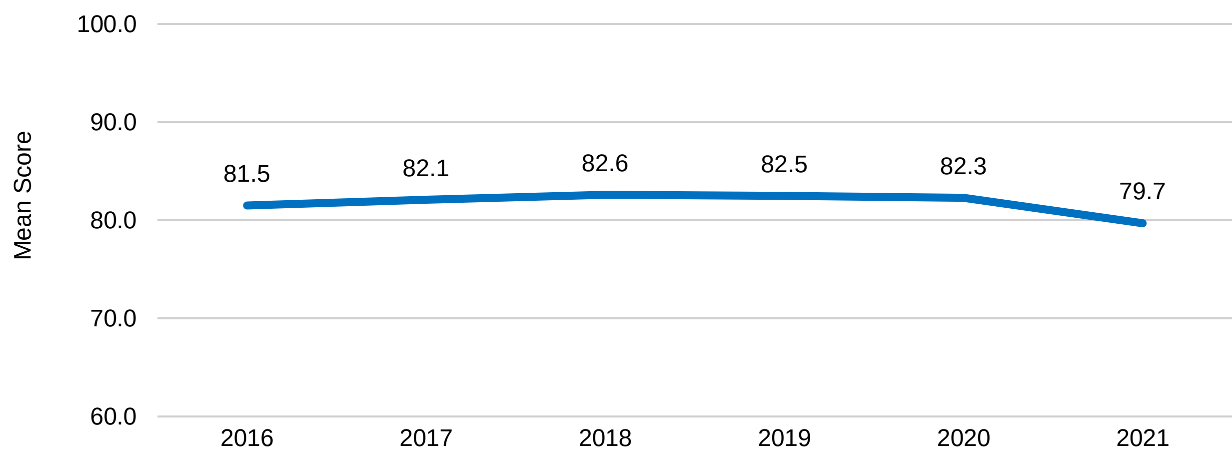
19 Toll free numbers costs $45,269 in 2018 compared to $8,690 in 2020 (45,269 - 8,690 / 45,269 = 81%).

20 It is estimated that annually a paper bill costs $12.79 more than an electronic bill. Therefore, 86,335 customers times 58 per cent at $12.79 per year equals approximately $640,000.

Customer satisfaction is assessed primarily through quarterly customer satisfaction surveys and a monthly grade of service.

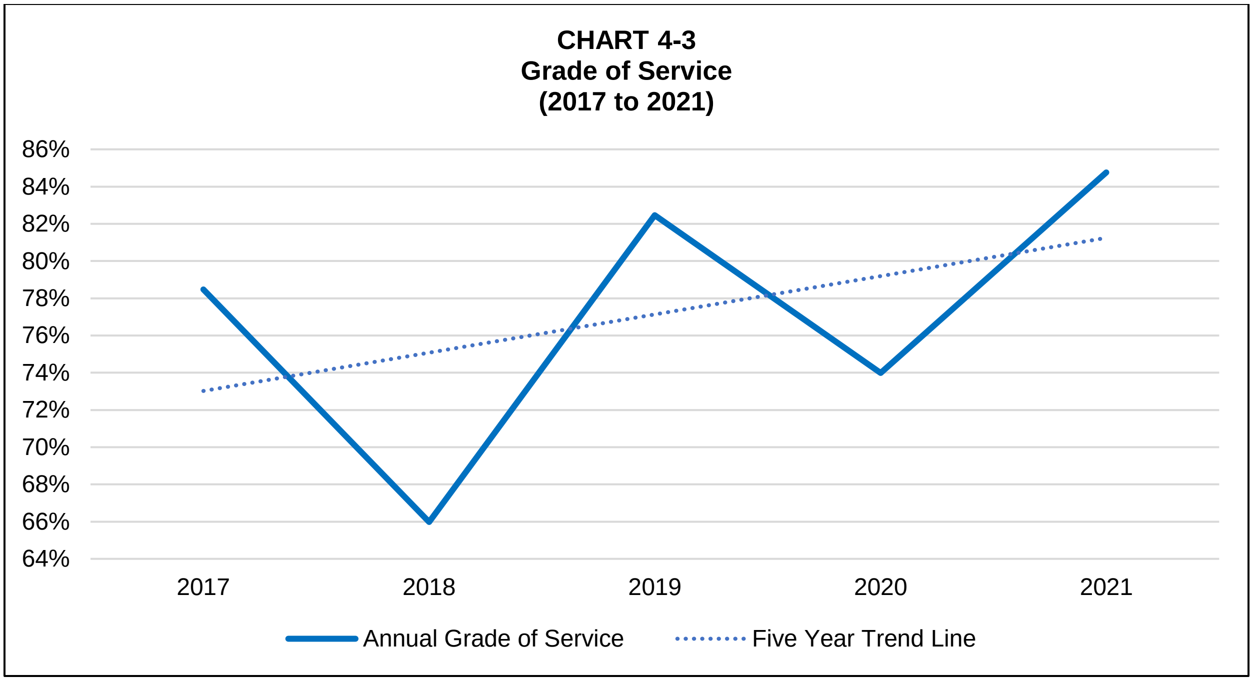
The quarterly customer satisfaction survey is conducted via phone by a third-party provider. Randomly selected customers are asked a series of questions regarding their perception of the overall service they receive. Chart 4-2 shows customers' overall satisfaction with Maritime Electric's service delivery, referred to as the customer service index, from 2016 to 2021.

CHART 4-2
Maritime Electric Customer Service Index
(Mean Score Average 2016 to 2021)



Customers' overall satisfaction with Maritime Electric's service delivery was 79.7 per cent in 2021 and averaged 81.8 per cent over the last six years. The lower-than-average satisfaction rating in 2021 was associated with customers' perception of: waiting too long to have their service installed/upgraded; the slow response to power line issues/concerns reported; and a lack of follow-up after an initial contact. The customer service index for the first quarter of 2022 was 83.8 per cent.

Maritime Electric's grade of service is based on the volume of customer calls answered in under 30 seconds. Chart 4-3 shows the Company's grade of service from 2017 to 2021.



The chart demonstrates that over the last five years an average of 81 per cent of customer calls were answered in under 30 seconds and, although it has varied, the trend shows overall improvements.

4.2 Operations and Reliability Management

4.2.1 System Overview

Maritime Electric owns and operates approximately 5,800 kilometres ("km") of distribution lines, 800 km of transmission lines, and 30 substations to serve customers throughout its service territory.

The Company owns and operates three combustion turbines with a total generating capacity of 90 MW. The primary role of these generation assets is to supply energy in times of curtailment from off-Island energy suppliers or during transmission line outages or curtailments, either on PEI or the mainland. The combustion turbines also provide backup for the four submarine cables connecting PEI to the mainland.

4.2.2 Electrical System Performance

Maritime Electric's electrical system is constructed to meet national standards.[21] These standards ensure the system operates safely and reliably under conditions the Company expects to occur throughout its service territory on a regular basis (i.e., normal operating conditions).

Measuring service reliability experienced by customers requires assessing both the duration and frequency of customer outages. Outage duration is measured using the System Average Interruption Duration Index ("SAIDI"), outage frequency is measured using the System Average Interruption Frequency Index ("SAIFI"), and outage interruption duration is measured using Customer Average Interruption Duration Index ("CAIDI").[22] While Maritime Electric records SAIFI and CAIDI performance, the Company focuses on SAIDI when assessing system reliability and prioritizing projects to improve it.

There are two SAIDI indices commonly used by utilities: (i) SAIDI (All In) measures reliability performance using outage data collected under all operating conditions; and (ii) SAIDI (MED Excluded) normalizes the outage data by removing significant outage events (i.e., major events) to reflect reliability performance under normal operating conditions or "blue sky" conditions.[23]

Comparing Maritime Electric's reliability to other Atlantic Canadian ("Atlantic") and Canadian utilities is a reasonable approach to assess the Company's reliability performance. In general, Maritime Electric's reliability during normal operating conditions is on par with the average reliability provided by other Canadian utilities.

Chart 4-4 shows the average duration of outages under normal operating conditions experienced by Maritime Electric customers, in comparison to the averages of other Atlantic and Canadian utilities from 2012 to 2021.

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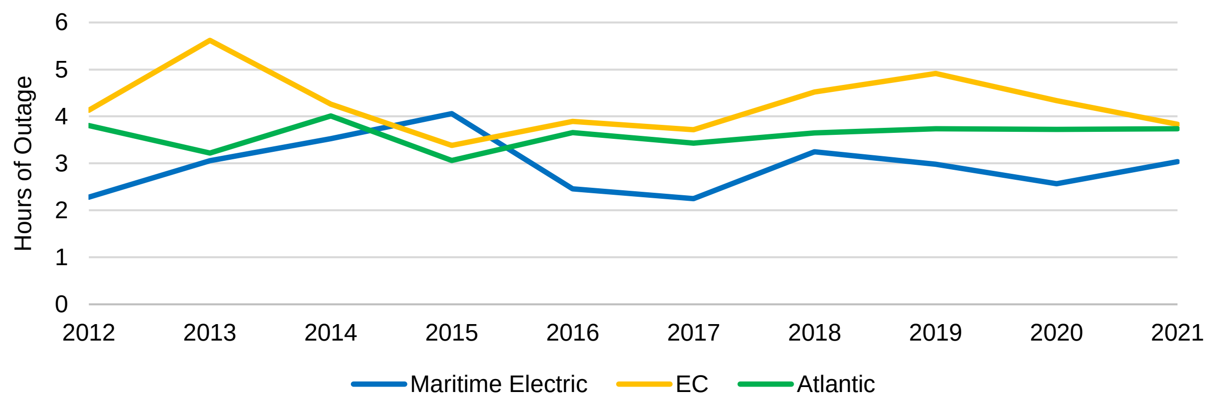
[21] The primary engineering standard is the Canadian Standards Association ("CSA") standard C22.3 No. 1:20, Overhead Systems. This standard guides the construction of overhead distribution and transmission systems.

[22] Maritime Electric calculates its reliability performance according to guidelines issued by Electricity Canada (formerly known as the Canadian Electrical Association). The Electricity Canada's recommended reporting standard is the Institute of Electrical and Electronics Engineers ("IEEE") Std 1366 – 2012, contained within the IEEE Guide for Electric Power Distribution Reliability Indices. All reliability data calculated by the Company follows this reporting standard.

[23] SAIDI (MED Excluded) was developed by the IEEE to address large outage data variances caused by major system disturbances that if otherwise included would make it difficult to track changes to the reliability performance of the electricity supply system under normal operating conditions.

CHART 4-4
SAIDI (MED Excluded)
Maritime Electric Comparison with other Atlantic and Canadian Utilities
2012 to 2021



Note: EC references Electricity Canada (formally known as Canadian Electricity Association) member utilities that serve a mix of urban and rural markets. These are ATCO Electric, BC Hydro, FortisAlberta, FortisBC, Hydro One, Hydro Quebec, Manitoba Hydro, Maritime Electric, NB Power, Newfoundland and Labrador Hydro, Newfoundland Power, Newmarket-Tay Power Distribution, Nova Scotia Power, Northwest Territories Power Corporation, SaskPower, Veridian Connections, Waterloo North Hydro, Yukon Electrical Co. and Yukon Energy.

Atlantic references NB Power, Newfoundland and Labrador Hydro, Newfoundland Power, and Nova Scotia Power.

The duration of Maritime Electric customer outages under normal operating conditions has improved since 2012 and has generally been lower than the other Atlantic and Canadian utility averages. Maritime Electric customers have experienced a range of approximately 2.3 to 4.1 average outage hours per year over this period.

The reliability of Maritime Electric's electrical system under normal operating conditions reflects the Company's diligence in monitoring performance metrics and responding with the appropriate balance of operating protocols and reliability targeted capital investments.

Operating protocols improve reliability through outage avoidance and outage response. Outage avoidance is accomplished primarily through scheduled inspection and maintenance along with live-line work methods.[24] The Company routinely inspects its electrical system to identify deteriorated equipment and make the necessary repairs or replacements. Substations are

[24] Live-line work methods refer to working on energized power lines.

inspected six times annually, transmission lines are inspected on a two-year cycle, and distribution lines are inspected on a six-year cycle. Equipment repairs or replacements are prioritized based on a combination of factors including risk of failure, safety and the likelihood of outages. When completing equipment repairs or replacements, the Company seeks to use live-line work methods that allow the maintenance to be performed safely without a customer outage.

Capital investments help to ensure that aged, deteriorated or overloaded components are replaced in a timely manner. The Company's Distribution Asset Management Program ("DAMP") is an example of an existing practice that prudently and effectively manages distribution assets balancing customer reliability and costs. The replacement of deteriorated assets and the refurbishment of assets to extend their useful service life is managed so that it is effective in the short term and sustainable in the long term. The refurbishment and replacement of distribution assets is principally based on asset condition, load growth and risks to customers in the event of a failure.

Despite all of the Company's best practices, Maritime Electric's electrical system regularly experiences the impact of extreme weather conditions. Severe wind and ice storms generally exceed the design parameters of the electrical system and can cause extensive damage.[25] Utility reporting standards consider these conditions to be "major events."[26]

Chart 4-5 shows the average duration of outages experienced by Maritime Electric customers including major events, in comparison to the averages of other Atlantic and Canadian utilities, from 2012 to 2021.

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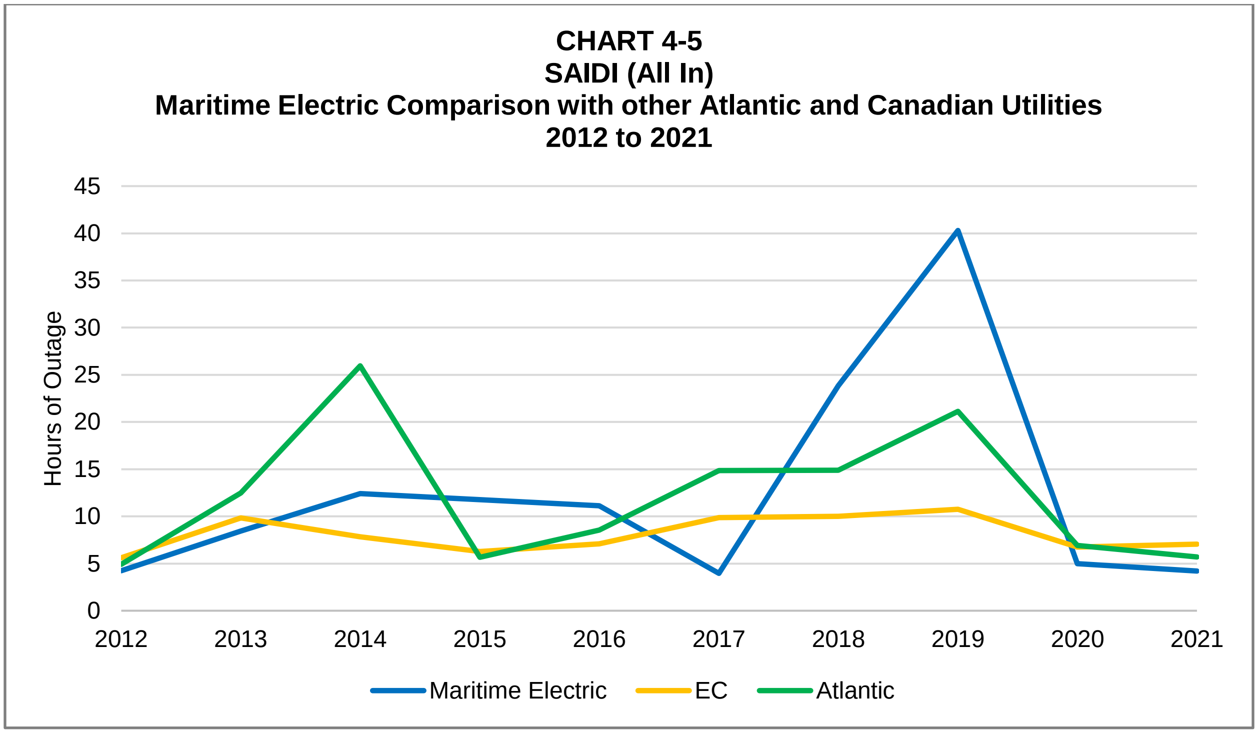
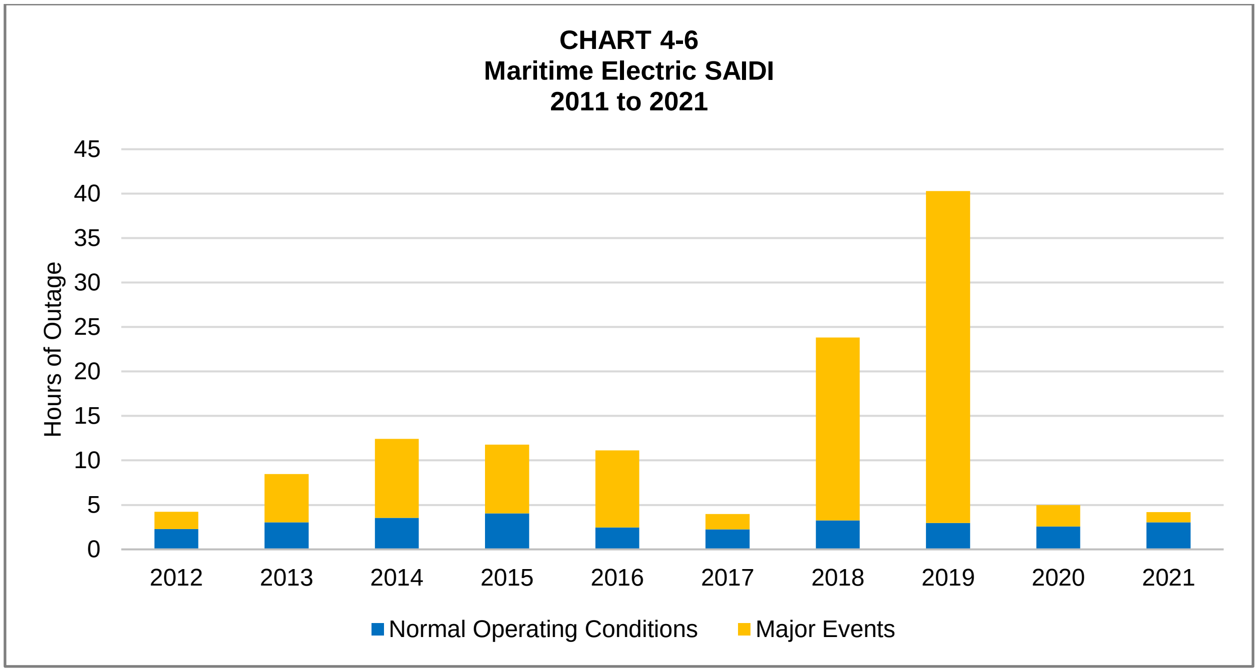
[25] Severe storms generally affect the duration of outages more than the frequency of outages. For example, a hurricane or an ice storm may result in a single outage that lasts several days.

[26] The IEEE defines a major event as "an event that exceeds reasonable design and or operational limits of the electric power system."



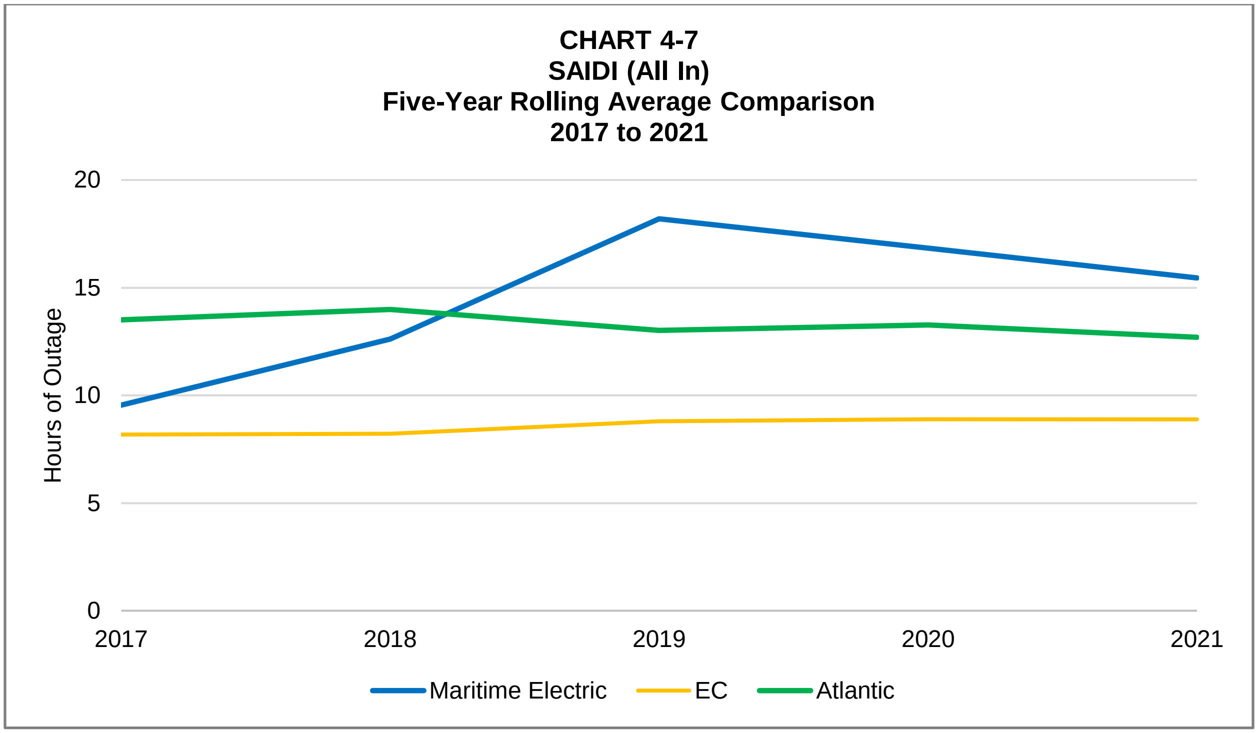
In 2015, 2016, 2018 and 2019 Maritime Electric's SAIDI (All In) was higher than the averages of other Atlantic and Canadian utilities. In each of these years, major events had a significant impact on outage duration in Maritime Electric's service territory, relative to normal operating conditions.

Chart 4-6 shows that major events are a regular occurrence on PEI, substantially impacting the service reliability experienced by customers. In 2018 a late-November ice storm was primarily responsible for an increase in average customer outage hours from 3.5 hours under normal operating conditions to almost 24 hours, and in September 2019 post-tropical storm Dorian increased the average customer outage hours from approximately 3 hours under normal operating conditions to over 40 hours.



The impact of major storm events on reliability is trending upward, indicating that major storm events are more common and have a more severe impact. This highlights the importance of systematically identifying and replacing aged and deteriorated system components, as well as taking other steps to harden the system so that it is better able to withstand major storm events.

When identifying reliability trends over time, Maritime Electric analyzes a five-year rolling average. Chart 4-7 shows Maritime Electric's five-year rolling average for SAIDI (All In) in comparison to the averages of other Atlantic and Canadian utilities from 2017 to 2021.



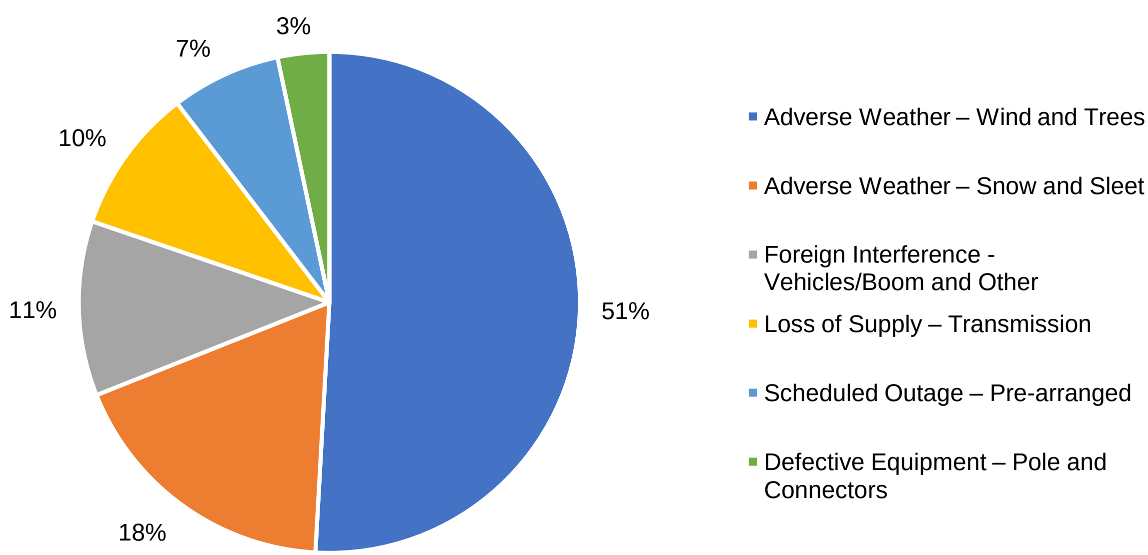
As demonstrated in Chart 4-7, Maritime Electric's five-year rolling average for SAIDI (All In) has trended upward and is higher than the averages of other Atlantic and Canadian utilities. Maritime Electric's five-year rolling average for SAIDI (All In) in 2021 was 15.45 hours, compared to 12.70 hours for the other Atlantic utilities average and 8.90 hours for the Canadian utilities average.

4.2.3 Reliability Management

Maritime Electric's operations continue to be focused on improving reliability for customers to reverse the upward trend of the five-year rolling average for SAIDI (All In).

To better understand how major outage events are impacting reliability, Maritime Electric completed a causal analysis review, the results of which are shown in Chart 4-8.

CHART 4-8
Cause Breakdown of Major Event Outage Hours
2011 to 2021



Over 50 per cent of major outage events were caused by wind and tree contacts, which suggests that system hardening and expanded vegetation management would have prevented many of these outages.[27]

Improving reliability during major events will require operational and system design changes. The required operational changes can be achieved through the Company's Vegetation Management Program. In this Application, Maritime Electric seeks approval to expand its Vegetation Management Program by shortening the vegetation management cycle for complete system coverage, which will require increasing annual operating expenditures for vegetation management through the rate-setting period and beyond.[28]

Several other initiatives are also being considered including: an increased focus on ground clearing in the provincial rights of way; a tree replacement program for the removal of trees on private property that impact power lines in the provincial rights of way; increased customer

[27] System hardening refers to the utility practice of installing equipment designed and built to be more resistant to severe weather.

[28] The vegetation management cycle for complete system coverage refers to the number of years before the Company returns to the same location to cut/trim the vegetation in the right of way.

education of the types of vegetation customers should plant and where to plant in order to avoid future trimming or ground cutting; and re-vegetation of cleared areas to prevent tree growth.

Improving system design will require capital investment. This Application does not seek approval of any system design changes. At this point, Maritime Electric is assessing what system design changes will best improve reliability for customers. For example, Maritime Electric is considering changes to line construction design inputs that would increase the ability of the electrical system to withstand weather events.[29] Once it is determined which system design changes should be undertaken to improve reliability performance, they will be incorporated into future capital budget applications for Commission approval.

4.2.4 Field Response

Field Response Performance

Maritime Electric maintains operational performance targets for new service connections. The performance benchmark requires new services to be connected within five business days 80 per cent of the time. This performance target has been met in each of the last five years with the average time for a new service connection being approximately 3.8 days.

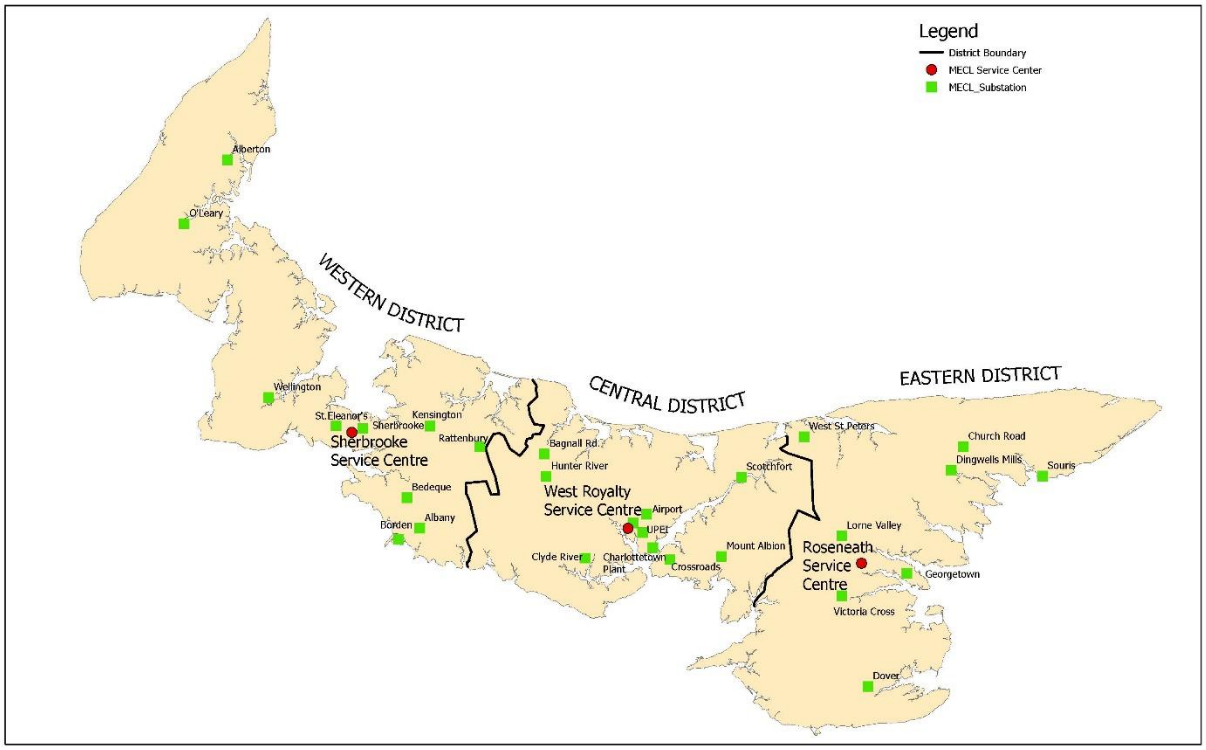
The Company uses a variety of operational technologies to estimate, specify, dispatch and manage work within each district. Contractor resources are used when the volume exceeds the Company's internal resource capability to respond in a timely manner.

Field Response Capabilities

As the primary electric utility on PEI, Maritime Electric must be responsive to customer outages and customer-driven work requests. The Company achieves this by using a combination of workforce management, operational technologies, and electrical system automation. When an outage occurs, the Company's response is prompt and crews are quickly dispatched to safely repair problems and restore power. The Company achieves this by maintaining a skilled workforce in each of its three districts, which covers a total service territory of approximately 5,630 square km. Figure 4-1 shows Maritime Electric's service territory including the location of substations, service centres and offices.

[29] Maritime Electric currently follows the Canadian Standards Association recommendations that overhead structures be built to withstand a half inch of radial ice and 100 km/hour winds at -20 degrees Celsius. However, major weather events are increasingly exceeding these parameters.

FIGURE 4-1
Maritime Electric Service Territory and Facilities



Maritime Electric's service territory is divided into three districts, each having a skilled workforce for maintenance activities, system outages and customer-driven work requests. Table 4-2 provides a breakdown of each district by number of customers, major infrastructure components and resources assigned to the district service territory. Some of the technical field staff and supervisors are located in a centralized location at the West Royalty Service Centre and are responsible for the capital and maintenance activities in all three districts.

TABLE 4-2 Customers and Resources by District			
	Western	**Central**	**Eastern**
Customers Served (#)	22,666	47,185	16,484
Substations (#)	11	11	8
Transmission Lines (km)	346	212	203
Distribution Lines (km)	2,045	2,020	1,715
Management Staff (#)	2	2	2
Power Line Staff (#)	18	24	13
Operations Support Staff (#)	1	1	1
Line Trucks (#)	6	10	5

Maritime Electric uses various systems to ensure the most accurate and timely information is used to monitor and restore the electrical system. Such systems include the survey system, work management system ("WMS"), geographic information system ("GIS"), and outage management system ("OMS"). In addition, field response capabilities are supported by automation throughout the electrical system.

The survey system is used to calculate service-related costs and any required contributions from the customer or joint-use partner. The survey system also creates detailed work instructions based on current design standards that are assigned to field crews.

The WMS allows work to be prioritized, scheduled, and assigned to field crews electronically. Service work, maintenance work and outage calls are dispatched to crews using the WMS. When work is completed by crews via the WMS the asset database is automatically updated, allowing a variety of information to be obtained and tracked. The WMS also allows crews to access drawings, standards, customer information and work instructions while in the field.

The GIS maps the Company's assets allowing crews to easily access and track asset information. The GIS maps are used to identify critical information related to customers, property, equipment locations, circuit information, abnormal conditions, pole ownership, and attachment information.

The OMS was enhanced in 2021 to include outage maps for internal use and external access via the Company's website. The enhanced OMS has the ability to input outage duration estimates that aids in notifying customers of expected restoration times, and improved the methods by which customers could report outages. The OMS uses customer call information, system automation reports, GIS information and employee inputs to create jobs and direct crews to the most probable outage cause locations, thus minimizing restoration times. During storm events with multiple outages, outage jobs are prioritized based on customer numbers, infrastructure criticality, and restoration duration estimates. Dispatch can assign work to field crews electronically and track important information regarding outage causes.

Maritime Electric uses a Supervisory Control and Data Acquisition ("SCADA") system to monitor and control various apparatus on the electrical system.

The SCADA system provides the Company's System Operators with the necessary data and specific pre-emergency and emergency alarms in order for them to monitor and respond to various system events. The SCADA system also provides a visual representation of transmission and distribution apparatus (i.e., lines, switches, reclosers, breakers, etc.) that enables the System Operator to efficiently troubleshoot problems and consider alternatives to minimize and respond to outages. The Company's substation circuits use remote-controlled apparatus, such as breakers, switches and reclosers, that significantly reduces the need to dispatch field crews by allowing the System Operator to perform many required functions remotely. The Company is strategically adding downline remote-controlled reclosers to improve reliability on long feeders with a large number of customers.[30]

4.3 Customer, Energy and Demand Forecast

Maritime Electric's methodology in developing the energy sales forecast for the rate-setting period is consistent with that used in recent filings.

In particular, the methodology is consistent with the Schedules of Rates effective March 1, 2020 and March 1, 2021 as filed on January 31, 2020 and reviewed by Grant Thornton. In its report dated October 12, 2020, Grant Thornton concluded that "Maritime Electric's approach to load forecasting is an acceptable methodology within the industry", that "the inputs and assumptions

[30] A downline remote-controlled recloser allows a fault to be isolated keeping upstream customers with power, thereby minimizing the impact of the outage.

within the energy sales forecast were supported", and "nothing [came to their] attention to indicate that the energy sales forecast for 2020 and 2021 is unreasonable".

4.3.1 Customers Served

Maritime Electric is the primary distributor of electricity on PEI and is responsible for serving more than 86,000 customers, which is forecast to increase to approximately 89,600 customers by 2025.

Table 4-3 provides the 2023 forecast number of customers, energy sales and total revenue by customer category.

TABLE 4-3
2023 Forecast Customer Base

Customer Category	% of Total Customers	% of Total Energy Sales	% of Total Revenue
Residential	84.4	52.0	55.9
General Service	11.0	28.8	29.9
Large Industrial	0.0[31]	11.7	6.9
Small Industrial	0.3	7.0	6.2
Street Lighting/Unmetered	4.3	0.5	1.1
Total	**100.0**	**100.0**	**100.0**

4.3.2 Energy Sales Forecast

Table 4-4 shows the actual energy sales for 2019 to 2021 and forecast energy sales for 2022 to 2025.

[31] There are seven Large Industrial customers.

TABLE 4-4 Energy Sales							
	2019 Actual	**2020 Actual**	**2021 Actual**	**2022[32] Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
Energy Sales[33] (gigawatt hours or GWh)							
Residential							
Space heating load[34]	178.4	176.8	171.8	222.8	229.8	244.3	258.8
Non-space heating load[34]	462.6	495.1	518.5	505.1	493.7	498.5	505.1
Subtotal	**641.0**	**671.9**	**690.3**	**727.9**	**723.5**	**742.8**	**763.9**
General Service	392.8	370.5	381.6	401.0	400.4	397.7	395.8
Large Industrial	154.0	151.8	153.8	163.5	163.5	168.0	168.0
Small Industrial	91.7	91.6	93.4	98.1	97.9	97.3	96.9
Street Lighting/Unmetered	7.4	7.0	6.9	6.4	6.4	6.4	6.5
Total Energy Sales	**1,286.9**	**1,292.8**	**1,326.0**	**1,396.9**	**1,391.7**	**1,412.2**	**1,431.1**
Growth Rate (%)							
Residential							
Space heating load	9.4	(0.9)	(0.6)	29.7	3.1	6.3	5.9
Non-space heating load	2.9	7.0	4.7	(2.6)	(2.2)	1.0	1.3
Subtotal	**4.6**	**4.8**	**2.7**	**5.4**	**(0.6)**	**2.7**	**2.8**
General Service	(0.2)	(5.7)	3.0	5.1	(0.1)	(0.7)	(0.5)
Large Industrial	1.5	(1.5)	1.3	6.3	-	2.8	-
Small Industrial	-	(0.1)	2.0	5.0	(0.1)	(0.7)	(0.4)
Street Lighting/Unmetered	(2.6)	(5.4)	(1.8)	(7.6)	-	1.0	1.0
Overall Growth Rate	**2.4**	**0.5**	**2.6**	**5.3**	**(0.4)**	**1.5**	**1.3**

Residential Sales

The residential sales forecast reflects the Conference Board of Canada's forecast of population growth on PEI, which is used to estimate the number of housing starts.[35] Each type of housing start (i.e., single-family detached, semi-detached and multi-family) is associated with a different level of electricity usage based on the estimated penetration of electric-space heating. The forecast non-space heating electricity usage reflects estimated incremental annual energy reductions of 6.5 GWh per year and 1.5 GWh per year associated with efficiencyPEI's programs

[32] 2022 forecast reflects actuals for January to March and forecast for April to December.
[33] Energy sales are based on a calendar year.
[34] Space heating load refers to the use of electricity to heat a home or building, while non-space heating load refers to all other uses of electricity.
[35] Conference Board of Canada Reports are provided in Appendix B.

and rooftop solar installations, respectively.[36] As a result, residential sales are forecast to increase by an average of 1.6 per cent annually over the rate-setting period.[37]

In comparison, actual residential sales increased approximately 4.0 per cent annually from 2019 to 2021.[38] A number of factors have contributed to the historical increases in residential sales year over year, some of which are not expected to continue through the rate-setting period.

The number of heating degree days ("HDD") experienced in 2019 to 2021 had a significant impact on the year-over-year change in residential energy sales.[39] HDD in 2019 were higher than normal, 2020 were lower than normal, and 2021 were even lower than 2020. This is evidenced by the negative growth rates for space heating load in 2020 and 2021. The space heating load forecast for 2022 assumes a return to the HDD 10-year average.

If HDD were held constant, the space heating load for residential sales would experience a steady increase driven by new housing starts, which are predominately installing electric heat sources, and the installation of heat pumps in existing housing, which is supported by government rebates. This is evidenced by the 3.1 to 6.3 per cent annual increase in space heating load during the rate-setting period.[40]

In addition, the energy sales forecast for 2022 reflects an actual increase in residential sales for the first quarter of 2022, which is attributed to customers resorting to short-term measures such as using portable electric space heaters in response to high furnace oil prices. The forecast assumes that furnace oil prices will moderate later in 2022 and the increased sales in the first quarter of 2022 will be temporary. The impact of higher actual energy sales in the first quarter of 2022 and the assumed return to the HDD 10-year average translates into the 29.7 per cent energy sales increase in 2022 over 2021 for residential space heating load.

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[36] On average, an estimated 1/3 of residential rooftop solar generation is used directly behind the meter to supply customer loads and, thus, represents a reduction in energy sales by the utility. The other 2/3 is delivered to the grid as a source of energy supply to the utility.

[37] (-0.6 + 2.7 + 2.8) / 3 = 1.6

[38] (4.6 + 4.8 + 2.7) / 3 = 4.0

[39] A heating degree day is a measurement designed to quantify the demand for energy needed to heat a building. It is the number of degrees that a day's average temperature is below 18 degrees Celsius, which is the temperature below which buildings need to be heated.

[40] The energy sales forecast assumes the HDD will be in line with the 10-year average.

The non-space heating load for residential sales in 2020 and 2021 was significantly impacted by the pandemic and the shift to working from home. With pandemic-related restrictions being lifted during 2022 and the expected return to work at the office, the non-space heating load for residential sales is forecast to return to pre-pandemic annual growth levels, which contributes to the 2.6 per cent decrease in 2022 compared to 2021.

During the rate-setting period, it is estimated that non-space heating load will increase approximately 1 per cent annually, with the exception of the 2023 decrease compared to 2022. This increase is comprised of an estimated annual increase of 2 per cent partially offset by an energy reduction forecast associated with efficiencyPEI's demand side management ("DSM") programs.

General Service Sales

General service sales are forecast to decline slightly over the rate-setting period.[41] The general service sales forecast includes an annual 1 per cent increase based on the Conference Board of Canada's assessment of PEI's forecast gross domestic product growth, which is forecast to average 1.4 per cent annually during the rate-setting period. However, this increase is more than offset by an estimated incremental annual reduction of 7.4 GWh associated with efficiencyPEI's DSM programs.

In comparison, actual general service sales decreased on average by 1 per cent annually from 2019 to 2021.[42] The decrease was driven by the temporary closure of non-essential businesses during the pandemic, and the forecast for 2022 assumes a return to pre-pandemic sales.

Large Industrial Sales

The large industrial sales category is currently comprised of seven customers. The forecast reflects energy sales consistent with 2021 actuals along with any known customer planned expansions.

[41] ((0.1) + (0.7) + (0.5)) / 3 = (0.4)
[42] ((0.2) + (5.7)+ 3.0) / 3 = (1.0)

Small Industrial Sales

The small industrial sales forecast reflects the same assumptions used for the general service forecast.

Street Lighting/Unmetered Sales

Street lighting sales have continuously declined since 2014 as the Company converts existing lights with more energy efficient light-emitting diode ("LED") lights. The forecast for the rate-setting period reflects that conversion being completed by 2023 followed by a minimal increase for the installation of new LED lights.

4.4 Operating and Capital Costs

4.4.1 Operating Costs

Operating costs account for approximately 10 per cent of the proposed average increase in customer electricity costs.[43]

Table 4-5 provides a summary of Maritime Electric's operating costs from 2019 to 2025. Transmission and distribution costs are discussed in Section 5.1.2 of this Application and general and administrative expenses are discussed in Section 5.1.3.

TABLE 4-5
Operating Costs ($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Transmission and Distribution	16,516	17,110	18,409	19,625	21,394	22,699	23,815
General and Administrative	9,484	10,634	12,329	12,854	13,185	13,559	13,972
Total	**26,000**	**27,744**	**30,738**	**32,479**	**34,579**	**36,258**	**37,787**

4.4.2 Capital Costs

Maritime Electric's annual capital budget reflects expenditures necessary to address a range of system and business requirements that support the Company's ability to fulfil its obligation as a

43 Refer to Chart 3-1 in Section 3.2.1 of this Application.

public utility under Section 3a of the *Electric Power Act*.[44] Through capital investment, the Company is able to serve existing and new customers, modify and expand the electrical system as necessary to meet customer demand and ensure security of supply, replace or upgrade aged, deteriorated or obsolete assets in a structured manner, improve system performance through design and technology enhancements, and ensure that the work support services are in place to meet business and regulatory requirements.

In accordance with Section 17 (1) of the *Electric Power Act*, the Company submits to the Commission, for its approval, an annual capital budget of proposed improvements or additions to its property. In accordance with Section 17 (4) of the *Electric Power Act*, the Company also reports on an annual basis its actual expenditures on improvements or additions to its property in the prior calendar year including explanations of variances within sixty days of the calendar year end.

Together, Commission approval of the annual capital budget in advance of the outlay of capital spending and the approval of actual capital expenditures incurred ensures the Company's ongoing capital program adheres to the strict regulatory approval process as required by the *Electric Power Act*.

Table 4-6 provides capital expenditures by asset class from 2019 to 2025.

[44] Section 3a of the *Electric Power Act* states "Every public utility shall furnish at all times such reasonably safe and adequate service and facilities for services as changing conditions require".

TABLE 4-6
Capital Expenditure by Asset Class ($000)

	2019 Actual[45]	2020 Actual[46]	2021 Actual[47]	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Generation	485	729	1,000	1,245	1,540	1,506	1,921
Transmission	7,721	7,655	9,257	8,889	15,343	15,325	18,440
Distribution	22,507	21,974	24,772	28,249	29,110	43,748	44,170
Corporate	1,434	1,687	2,311	4,035	6,445	11,485	9,062
Subtotal	**32,147**	**32,045**	**37,340**	**42,418**	**52,438**	**72,064**	**73,593**
General Expense Capitalized	568	490	681	690	721	739	758
Interest During Construction	474	444	548	496	682	950	961
Contributions	(759)	(1,157)	(1,482)	(3,538)	(2,250)	(10,250)	(8,750)
Subtotal	**32,430**	**31,822**	**37,087**	**40,066**	**51,591**	**63,503**	**66,562**
Prior Year Carryovers[48]	2,641	2,723	5,082	13,641	8,000	7,000	6,000
Carryovers to Following Year[49]				(8,000)	(7,000)	(6,000)	(5,000)
Total	**35,071**	**34,545**	**42,169**	**45,707**	**52,591**	**64,503**	**67,562**

Over the rate-setting period, incremental amounts of capital investment are required. Capital investment, excluding prior year carryovers, in 2023 is forecast to be $11.5 million higher than 2022, 2024 is forecast to be $11.9 million higher than 2023, and 2025 is forecast to be $3.1 million higher than 2024.

During the rate-setting period, significant investment is required in transmission. The pending 2023 Capital Budget Application will provide the necessary information to support a new substation in Tignish ($2.6 million in 2023 and $2.3 million in 2024), a switching station in Woodstock ($1.7 million in 2023, $6.0 million in 2024 and $6.2 million in 2025), and the second year of a substation upgrade in Crossroads ($3.3 million in 2023). The 2023 forecast for

45 The Company’s 2019 Capital Budget Application was approved in Order UE18-09, and the 2019 Capital Forecast Variance Report was approved in Order UE21-02.

46 The Company’s 2020 Capital Budget Application was approved in Orders UE19-09 and UE20-02, and the 2020 Capital Forecast Variance Report was approved in Order UE21-16.

47 The Company’s 2021 Capital Budget Application was approved in Order UE21-16, and the 2021 Capital Forecast Variance Report was approved in Order UE22-02.

48 The total carryovers for 2022 includes the budget to construct a new building to house equipment related to combustion turbine #3 at the CTGS submitted to the Commission for approval in a Supplemental Capital Budget Request for $4.168 million on June 7, 2021 and approved by the Commission on May 13, 2022 in Order UE22-03.

49 It is expected that supply chain issues related to the pandemic may take several years to fully resolve and carryovers to future years will gradually reduce over the rate-setting period.

transmission also reflects the second year of the West Royalty X5 autotransformer upgrade for $4.6 million.[50]

Significant investment is forecast in distribution in 2024 and 2025, which reflects the launch of a multi-year project to transition to advanced metering infrastructure (net $12.5 million in 2024 and net $11.8 million in 2025)

The Corporate category, which includes property management and information technology, reflects a multi-year project beginning in 2023 to replace the Company's customer information and billing system ("CIS") ($3.2 million in 2023, $6.5 million in 2024 and $6.3 million in 2025). The Corporate category also reflects the construction of a new service depot in the western district ($1.5 million in 2024).

50 Section 6.1 (c) of the 2022 Capital Budget Application forecast year two of the West Royalty X5 autotransformer upgrade at $2.7 million. The revised forecast of $4.6 million reflects changes in project scope and the impact of inflation on large transformer equipment.

5.0 COST OF SERVICE AND PROJECTIONS

5.1 Cost of Service

This section of the Application presents the forecast cost of service for the rate-setting period. Consistent with the development of the sales forecast in Section 4.3 of this Application, the cost of service elements are forecast based on the methodology used in the previous GRA, which was reviewed by Grant Thornton. Assumptions and inputs have been updated to reflect the best information available.

In supporting the forecast cost of service, an analysis of actual costs for 2019 to 2021 is also presented, with a detailed analysis in Appendix C. Forecasts are based primarily on historical costs adjusted for inflation. Forecast costs are also decreased to remove the impact of past events or cost patterns that are not expected to occur during the rate-setting period and increased to reflect new information going forward.

With respect to inflation, the Company has historically assumed inflation in the range of 2 to 3 per cent per year, and this assumption was maintained in the forecast of the cost of service for the rate-setting period. However, recent indications are that inflation in the short term will materially exceed historical levels. For March 2022, Statistics Canada reported that PEI had the highest inflation rate across Canada at 8.9 per cent.[51] While this level of inflation is not expected to continue throughout the rate-setting period, inflation is likely to exceed the 2 to 3 per cent that the Company assumed. Therefore, the Company is assuming some inflation risk in the forecast cost of service for the rate-setting period.

5.1.1 Energy Supply Costs

Energy supply costs account for approximately 46 per cent of the Company's forecast rate increase,[52] and is comprised of energy purchase costs and/or energy generation to meet the Company's obligation to supply energy to its customers under the *Electric Power Act*.

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[51] Statistics Canada report dated April 20, 2022: https://www150.statcan.gc.ca/n1/daily-quotidien/220420/t002a-eng.htm.

[52] Per Chart 3-1 in Section 3.2.1 of this Application.

Energy supply costs have two primary drivers, energy purchases and capacity.

To meet customers' energy demand and supply requirements, the Company has a contractual entitlement to energy and capacity from NB Power's Point Lepreau Nuclear Generating Station ("Point Lepreau") and an agreement for the purchase of firm/system energy and capacity with New Brunswick Energy Marketing ("NBEM") delivered via four submarine cables leased from the Province of PEI. The Company also purchases 92.5 MW of wind-powered energy under contract with the PEIEC and maintains 89 MW (net) of on-Island generating capacity.

Energy purchases are based primarily on the energy sales forecast, as discussed in Section 4.3.2 of this Application, to which system losses and the Company's own usage is added. The resulting total, presented in Table 5-1, is referred to as the net purchased and produced ("NPP") energy requirement and represents the total amount of energy that must be acquired to supply the system.

TABLE 5-1
Net Purchased and Produced Energy (GWh)

Description	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Energy Sales	1,286.9	1,292.8	1,326.0	1,396.9	1,391.7	1,412.2	1,431.1
Company Use and System Losses[53]	98.4	99.0	105.6	107.3	107.0	105.2	106.5
Total	**1,385.3**	**1,391.8**	**1,431.6**	**1,504.2**	**1,498.7**	**1,517.4**	**1,537.6**

Annual Company use consists of the energy used to provide lighting, general service and heating. System losses occur in the delivery of energy to customers, and must be included in the estimate of the energy requirement.

To source the energy required to supply the forecast NPP, Maritime Electric first sources energy supply from Point Lepreau and renewable sources because they are based on take-or-pay contracts. Renewable sources are secondary to Point Lepreau due to their intermittent nature. The remainder of the energy supply is principally sourced via the Energy Purchase Agreement ("EPA") with New Brunswick Energy Marketing ("NBEM").

[53] Company use and system losses includes heating of the CTGS since the facility was placed into long-term layup in 2019. It is assumed that the facility will no longer need to be heated from 2024 onward.

The expected peak load and associated capacity requirement is also derived from the energy sales forecast. The forecast capacity requirement is then sourced according to the available capacity resources.

Table 5-2 provides the energy supply costs by source for 2019 to 2025. A variance analysis is provided in Appendix C.

TABLE 5-2
Energy Supply Cost by Source ($000)

Description	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Point Lepreau[54]	24,442	23,985	25,758	24,529	25,481	24,661	25,647
Commercial Wind and Solar[55]	24,599	24,958	23,658	24,472	26,635	37,187	50,637
EPA with NBEM:							
Firm Energy	59,046	65,739	73,305	86,057	81,978	77,269	65,475
Secure/Assured Energy	8,725	4,759	6,042	478	124	-	-
Ancillary and Other Services	(3)	207	(606)	-	-	-	-
Company-Owned Generation:							
CTGS	1,440	1,173	802	289	-	-	-
CT3	598	429	650	815	1,164	1,351	1,596
CT1 and CT2	310	313	426	608	607	675	893
Energy Control Centre	952	949	1,000	1,127	1,106	1,154	1,206
Interconnection Costs	4,588	4,602	4,986	4,798	4,605	4,631	4,653
Other NB Power Charges[56]	1,495	1,500	1,504	1,629	1,753	1,761	1,793
Provincial Debt Repayment Cost[57]	-	-	-	-	4,103	5,411	5,457
Other Energy Supply Costs	828	905	1,020	1,228	1,330	1,384	1,441
Total	**127,020**	**129,519**	**138,545**	**146,030**	**148,886**	**155,484**	**158,798**

[54] The forecast energy supplied by Point Lepreau reflects no scheduled outages in 2023 and 2025, and a 50-day scheduled outage in 2024.

[55] The wind and solar forecast reflects the addition of a 10 MW solar farm in 2023, a 30 MW wind farm in 2024 and a 40 MW wind farm in 2025.

[56] Other NB Power charges include facilities rental and transmission services.

[57] In 2019 to 2022, Provincial debt repayment costs were and are recovered from customers via a rate rider. Effective March 1, 2023, this Application proposes that these costs be included in the Company's revenue requirement.

Point Lepreau

Point Lepreau costs are in accordance with the Point Lepreau Participation Agreement and the forecast costs reflect inputs from NB Power. NB Power provides a detailed forecast of Maritime Electric's share of the facilities operating and maintenance costs reflecting planned outages for required maintenance.

During the rate-setting period, a single 50-day outage is scheduled for April to May 2024 and replacement energy will be sourced via the EPA. In comparison, a 42-day outage occurred in 2019, a 61-day outage occurred in 2020, three outages occurred in 2021 totalling 100 days, and a 60-day outage is scheduled for April to June 2022.

Commercial Wind and Solar

The Company has a total of 92.5 MW of wind generation under contract with the PEIEC, with an additional 80 MW of commercial wind and solar expected to be in service throughout the rate-setting period, as summarized in Table 5-3.

TABLE 5-3 Commercial Wind and Solar Generation Contracts (MW)	
North Cape	10.5
East Point	30.0
Hermanville	30.0
Norway – Engie	9.0
Norway – Aeolus	3.0
Norway – WEICan	10.0
Subtotal – Existing	**92.5**
Slemon Park Solar Micro-Grid – January 1, 2023	10.0
New Wind Facility – January 1, 2024	30.0
New Wind Facility – January 1, 2025	40.0
Total – Expected[58]	**172.5**

EPA with NBEM

The EPA provides energy pricing in three tiers. The first tier, firm energy purchases, is used when Point Lepreau and on-Island wind generation is not capable of providing Maritime Electric's

[58] Expected in-service dates are based on the latest information provided by PEIEC.

forecast load requirement. The second and third tiers, which are referred to as secured and assured energy purchases, respectively, are used when Maritime Electric's energy needs exceed the contractual limit for firm energy, and both can be curtailed based on predefined situations with varying notice periods. Maritime Electric is responsible for the capacity to provide back-up energy for the second and third tier energy purchases.[59]

The forecast assumes that Maritime Electric's energy purchases will not exceed the forecast load requirement; therefore, there are no secure or assured energy purchases included in the forecast, with the exception of 2023. In 2022 a ratchet clause in the EPA was triggered resulting in the requirement to purchase some secure energy in 2023.[60]

Ancillary services are set out in NB Power's Open Access Transmission Tariff ("OATT") and include: load following, regulation, imbalance, spinning reserve, non-spinning reserve, reactive power supply and voltage control. The rates for ancillary services vary based on NB Power's costs to administer and supply these services and on the Company's peak load in comparison to the peak load in the Maritimes, as ancillary services are allocated based on the Company's share of the Maritime peak load.

Other services refers to a variety of miscellaneous charges, the largest of which is the provision of off-Island energy purchases during times when the EPA has been curtailed.[61] This category also includes the off-Island sale of energy when requested.[62] Maritime Electric does not forecast for the off-Island sale of energy.

Company-Owned Generation

The primary role of the Company's generation assets is to supply energy in times of curtailment from off-Island energy suppliers or during transmission line outages or curtailments, either on PEI or the mainland. The combustion turbines also provide backup for the four submarine cables

59 CT3 provides capacity for secure energy purchases, and CT1 and CT2 provide some capacity for assured energy purchases and non-spinning ancillary services.

60 The ratchet clause is triggered when the actual energy purchased under the EPA exceeds or falls short of the level negotiated in the EPA by various percentages. The current negotiated energy levels reflect an in-service date of January 1, 2021 for the new 30 MW wind farm in eastern PEI.

61 When subject to curtailment, the Company's generation is used to supply replacement energy if it is cheaper than off-Island replacement energy.

62 On occasion, Maritime Electric is required to generate electricity to supply NB Power or Nova Scotia Power, in which case the full cost of generation is recovered.

connecting PEI to the mainland, and have the added benefit of providing on-Island capacity that does not need to be purchased.

The CTGS generation units were placed into warm, long-term layup effective March 1, 2019 and continued to be available to generate as required until December 31, 2021, at which point the units were retired. Costs associated with CTGS primarily relate to heating and maintaining the building, which continues to be necessary as long as equipment associated with the operation of CT3 is located in the CTGS building. The forecast reflects the avoidance of any additional heating and maintenance costs beyond 2022 as a result of the Commission's approval to construct a new building to house the CT3 equipment.

The Company's three combustion turbines are forecast to be used for stand-by and emergency purposes with a provisional amount of generation that allows for periods of curtailment of contract energy and transmission curtailment in New Brunswick. This category provides for labour, non-labour and fuel costs. During the rate-setting period, labour and non-labour forecasts reflect inflationary increases offset by labour savings in 2023 and 2024 as employees are temporarily reassigned to CTGS decommissioning activities and returning to combustion turbine maintenance and production duties in 2025. The 2022 to 2025 forecasts for fuel costs are based on monthly testing requirements and generation to meet load requirements, using a forecast fuel price based on the US Energy Information Administration Forecast at the time Maritime Electric's forecast was prepared.[63]

Energy Control Centre

The Company's Energy Control Centre ("ECC") is an integral part of the electrical system that is responsible for scheduling hourly energy purchases, monitoring and operating the Company's transmission and distribution system, managing the submarine cable loading, and dispatching on-Island generation when required. Costs associated with the ECC include internal labour, training and communication costs. During the rate-setting period forecasts are based on historical actuals adjusted for inflation.

[63] US Energy Information Administration Forecast is released once a year and was dated April 2022.

Interconnection Costs

The interconnection costs include: (i) the interconnection lease payments for the two newer submarine cables; (ii) NB Power's OATT Schedule 9 – Direct Assignment charges for the transmission lines from Memramcook to Cape Tormentine; (iii) the Company's required contributions to the PEIEC's cable contingency fund; and (iv) maintenance costs associated with Murray Corner and Memramcook switching stations in New Brunswick.

Other NB Power Charges

This category provides for the use of NB Power's transmission assets, including: (i) operating and maintenance charges for the use of NB Power's transmission lines; (ii) operating and maintenance charges for the use of NB Power's Memramcook terminal station; (iii) a circuit breaker rental fee; (iv) fees to utilize the Open Access Technology Inc. ("OATI") e-tagging system for entering energy requirements; and (v) the cost to purchase and secure transmission capacity in New Brunswick associated with the 30 MW International Power Line.

Provincial Debt Repayment Costs

This category provides for the annual payment of costs recoverable from customers on behalf of the Province. The provincial debt repayment costs reflect the PEIEC's expected financing arrangements for those deferred energy costs assumed by the Province under the PEI Energy Accord. The debt repayment costs are based on the April 2021 Debt Collection Agreement with the PEIEC.

Section 5.3.6 of this Application discusses the treatment of a forecast under-collection balance related to the provincial debt repayment costs as of February 28, 2023.[64]

Other Energy Supply Costs

Other costs include insurance, property tax and training costs.

Insurance is the cost of providing the necessary property, equipment and liability insurance coverage for the Company's generating assets as well as the Provincially owned submarine cables.

[64] Currently, the provincial debt repayment costs are collected from customers via a rate rider. Effective March 1, 2023, it is proposed that the costs be included in the Company's revenue requirement instead.

Property tax is associated with the Company's generating facilities based on the assessed values of the physical properties.

Training is associated with the employees responsible for maintaining the Company's generating assets and ECC operations.

5.1.2 Transmission and Distribution Costs

The Company's transmission and distribution operations are a key aspect to ensuring the electrical system provides reliable service to customers. Table 5-4 provides a summary of the transmission and distribution costs for 2019 to 2025 with a breakdown of each category that follows. Refer to Appendix C for a detailed year-over-year analysis for 2019 to 2021 along with a discussion of 2022 to 2025 forecast costs.

TABLE 5-4
Transmission and Distribution Costs ($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Transmission	671	739	1,077	1,065	1,171	1,279	1,386
OATT	8,520	8,820	8,788	10,259	11,421	11,611	11,813
Distribution	5,031	5,187	6,031	5,708	6,109	6,943	7,607
Other	2,294	2,364	2,513	2,593	2,693	2,866	3,009
Total	**16,516**	**17,110**	**18,409**	**19,625**	**21,394**	**22,699**	**23,815**

Transmission Costs

Table 5-5 provides a further breakdown of the transmission costs by activity for 2019 to 2025.

TABLE 5-5
Transmission Costs ($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Substations	62	67	69	80	82	89	91
Rights of Way	143	230	544	397	473	551	627
Line Maintenance	290	245	260	322	326	333	354
Line Control Devices	47	55	61	79	81	83	85
Engineering	129	142	143	187	209	223	229
Total	**671**	**739**	**1,077**	**1,065**	**1,171**	**1,279**	**1,386**

Substations

This category provides for the inspection and maintenance of the Company's transmission substations. During the rate-setting period, substation costs are forecast to increase by an average of 4.4 per cent annually. In comparison, actual increases from 2019 to 2021 averaged 5.5 per cent annually, which were materially in accordance with approved forecasts.

The increase in substation costs from 2019 to 2021, beyond inflationary pressures, is a direct result of increasing customer load growth. To respond to load growth, the number of transmission substations have increased by 25 per cent over the last 10 years, from 24 substations in 2011 to 30 in 2021. As the number of substations increases so too does the related inspections, repairs and maintenance.

Rights of Way

This category provides for the inspection and maintenance of transmission rights of way, also referred to as the vegetation management, for the Company's approximately 800 km of transmission lines.

Appendix E discusses the requirement to increase the forecast for vegetation management activities during the rate-setting period and beyond to improve reliability for customers.

Line Maintenance

This category provides for the inspection and maintenance of the transmission assets. These costs are driven by preventative maintenance activities and responding to outages, including those caused by weather events. During the rate-setting period, line maintenance costs are forecast to increase by an average of 3.2 per cent annually. In comparison, actual costs from 2019 to 2021 decreased by an average of 4.7 per cent annually, which was driven by lower-than-planned weather-related outages in 2021.

The increase in line maintenance costs from 2019 to 2025, beyond inflationary pressures, is related primarily to hiring power line technician apprentices to replace retirements expected in 2023 and beyond.[65]

[65] Power line technician apprentices require four years to become fully qualified.

Line Control Devices

This category provides for the inspection and preventative maintenance of transmission control devices such as capacitors, circuit breakers and switches. During the rate-setting period, costs are forecast to increase by an average of 2.5 per cent annually. In comparison, actual costs from 2019 to 2021 increased by an average of 14.0 per cent annually, which was materially in accordance with approved forecasts.

As the number of transmission substations increased over the last ten years, so too did the number of line control devices. The forecasts for 2023 to 2025 reflect that increase along with adjustments for inflation.

Engineering

This category provides for the engineering support and analysis required to design, operate and maintain the transmission system. During the rate-setting period, costs are forecast to increase by an average of 7.1 per cent annually. In comparison, actual costs from 2019 to 2021 increased by an average of 5.4 per cent annually, which was materially in accordance with approved forecasts.

The forecasts for 2023 to 2025 are based on historical actuals adjusted for inflation along with additional engineers required to support the capital program and related operating requirements.

OATT

This category includes the cost that Maritime Electric charges itself for transmission services.[66] Table 5-6 provides a breakdown of the OATT costs for 2019 to 2025.

[66] The cost of providing transmission service is captured primarily in the main transmission cost categories along with depreciation, interest, income taxes and return.

TABLE 5-6 OATT Costs ($000)							
	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Network Service	7,545	7,809	7,984	9,317	10,577	10,752	10,938
Schedule 1	237	245	250	261	267	271	275
Schedule 2	316	327	335	271	195	198	202
Schedule 3C	13	16	14	-	-	-	-
Schedule 4	104	138	(88)	-	-	-	-
Schedule 9	67	67	67	67	66	66	66
Operations[67]	238	218	226	343	316	324	332
Total	**8,520**	**8,820**	**8,788**	**10,259**	**11,421**	**11,611**	**11,813**

During the rate-setting period, Maritime Electric's OATT costs are based on the sales and load growth forecast and the proposed OATT rates effective July 1, 2022.[68]

Distribution Costs

Table 5-7 provides a further breakdown of the distribution costs by activity for 2019 to 2025.

TABLE 5-7 Distribution Costs ($000)							
	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Substations	101	120	109	122	126	129	135
Rights of Way	1,596	1,414	2,766	1,831	2,144	2,773	3,362
Line Maintenance	1,805	2,145	1,569	2,059	2,094	2,241	2,242
Line Control Devices	56	37	41	55	56	57	59
Transformers	701	638	659	637	641	655	694
Meters	173	163	165	190	194	199	204
Communication Systems	160	211	236	251	258	264	271
Supervisory SCADA	89	93	101	121	124	128	131
Engineering	350	366	385	442	472	497	509
Total	**5,031**	**5,187**	**6,031**	**5,708**	**6,109**	**6,943**	**7,607**

67 Operations are the costs associated with administering the OATT and are primarily labour costs.
68 Proposed OATT rates were submitted to the Commission on July 31, 2020 for approval.

Substations

This category provides for the inspection and maintenance of the Company's distribution substations. During the rate-setting period, substation costs are forecast to increase by an average of 3.4 per cent annually. In comparison, actual costs from 2019 to 2021 increased by an average of 4.8 per cent annually, which was materially in accordance with approved forecasts.

The forecasts for 2023 to 2025 are based on historical actuals adjusted for inflation along with a shift to internal labour from contractors as internal resources return to substation maintenance in 2024 upon the expected completion of the CTGS decommissioning project.

Rights of Way

This category provides for the inspection and maintenance of vegetation within the distribution rights of way, which covers approximately 5,800 km.

Appendix E discusses the requirement to increase the forecast for vegetation management activities during the rate-setting period and beyond to improve reliability for customers.

Line Maintenance

This category provides for the inspection and maintenance of the distribution assets. These costs are driven by preventative maintenance activities, customer requests and responding to outages, including those related to weather events. During the rate-setting period, line maintenance costs are forecast to increase by an average of 2.9 per cent annually. In comparison, actual costs from 2019 to 2021 decreased by an average of 4.0 per cent annually, which was materially in accordance with approved forecasts, with the exception of the decrease in 2021.

Line maintenance costs in 2021 were 23 per cent below forecast driven by fewer weather-related outages and a delay in the hiring of power line technician apprentices.

The forecasts for 2023 to 2025 are based on historical actuals adjusted for inflation, and assumes responding to weather-related outages based on the 10-year average.

Line Control Devices

This category provides for the inspection and maintenance of the distribution control devices such as capacitors, voltage regulators and reclosers. During the rate-setting period, line control device costs are forecast to increase by an average of 2.4 per cent annually. In comparison, actual costs from 2019 to 2021 decreased by an average of 11.6 per cent annually, as a result of 2019 costs being higher than costs in 2020 and 2021.

The forecasts for 2023 to 2025 reflect historical actuals adjusted for inflation.

Transformers

This category provides for the inspection and maintenance of distribution transformers, which includes both pole-mount and pad-mount units. During the rate-setting period, transformer costs are forecast to increase by an average of 2.9 per cent annually. In comparison, actual costs from 2019 to 2021 decreased by an average of 2.8 per cent annually, which was driven by higher-than-planned costs in 2019 related to post-tropical storm Dorian.[69]

The forecasts for 2023 to 2025 are based on historical actuals adjusted for inflation and the reassignment of internal resources to deal with increased transformer workload.

Meters

This category provides for the inspection, testing and maintenance of approximately 87,000 revenue meters to remain compliant with Measurement Canada's rules and regulations. During the rate-setting period, meter costs are forecast to increase by an average of 2.4 per cent annually. In comparison, actual costs from 2019 to 2021 decreased by an average of 2.3 per cent annually, which was materially in accordance with approved forecasts.

The forecasts for 2023 to 2025 are based on historical actuals adjusted for inflation.

Communication Systems

This category provides for the operation and maintenance of the Company's communication hardware and telecommunication equipment. During the rate-setting period, communication

[69] Between September 7, 2019, when post-tropical storm Dorian made landfall on PEI, and September 15, 2019, when power was restored to all customers, costs incurred were captured in a deferral account. Repairs and clean-up related to the storm was required beyond that period and such costs were expensed.

system costs are forecast to increase by an average of 2.6 per cent each year. In comparison, actual costs from 2019 to 2021 increased by an average of 21.9 per cent, as a result of 2019 costs being unexpectedly low due to employees being reassigned to other departments to assist with lingering clean-up from post-tropical storm Dorian.

The 2023 to 2025 forecasts are based on a normalization of historical actuals adjusted for inflation.

Supervisory SCADA

This category provides for the maintenance of the Company's supervisory control and data acquisition ("SCADA") system, which collects, analyzes and visually displays data from the transmission and distribution system. The data is transmitted via the communication system to the Company's ECC. During the rate-setting period, costs are forecast to increase by an average of 2.7 per cent annually. In comparison, actual costs from 2019 to 2021 increased by an average of 6.5 per cent annually, which was materially in accordance with approved forecasts.

The forecasts for 2023 to 2025 are based on a normalization of historical costs adjusted for inflation.

Engineering

This category provides for the engineering support and analysis required to design, operate and maintain the distribution system. During the rate-setting period, costs are forecast to increase by an average of 4.8 per cent annually. In comparison, actual costs from 2019 to 2021 increased by an average of 4.9 per cent annually, which were materially in accordance with approved forecasts, with the exception of delayed retirement replacements and a parental leave that was not backfilled.

The 2023 to 2025 forecasts are based on historical actuals adjusted for inflation and the addition of engineers required to support the capital program and related operating requirements.

Other Transmission and Distribution Costs

Table 5-8 provides a further breakdown of the other transmission and distribution costs for 2019 to 2025.

TABLE 5-8
Other Transmission and Distribution Costs ($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Insurance	144	166	203	226	239	252	266
Property Tax	2,050	2,125	2,213	2,273	2,358	2,515	2,642
Employee Training	100	73	97	94	96	99	101
Total	**2,294**	**2,364**	**2,513**	**2,593**	**2,693**	**2,866**	**3,009**

Insurance is procured by Fortis Inc. on behalf of its group members, which allows Maritime Electric to obtain insurance coverage on assets that is economically priced. The buying power of Fortis Inc. provides an insurance cost that is much lower than what the Company could procure if it were seeking coverage independently. During the rate-setting period, insurance costs are forecast to increase by 5.5 per cent annually as predicted by Fortis Inc.'s insurance specialist. In comparison, actual costs from 2019 to 2021 increased by an average of 19.0 per cent annually, which was due to challenging renewal markets following catastrophic weather events and wild fires experienced in North America.

Property taxes relate to the land on which the Company's transmission and distribution assets are located. Property tax is levied as either a tax on physical properties based on their assessed values or a revenue-related tax calculated at 1.0 per cent of the Company's annual revenue from the prior year. During the rate-setting period, property taxes are forecast to increase by 5.2 per cent annually, which is based on 1.0 per cent of the prior years' forecast revenue. In comparison, actual increases from 2019 to 2021 have averaged 3.9 per cent annually, which was materially in accordance with approved forecasts.

Employee training ensures a skilled workforce required to maintain a reliable transmission and distribution system. During the rate-setting period, training costs are forecast to increase by 2.5 per cent annually, in line with inflation. In comparison, actual training costs from 2019 to 2021 and forecast for 2022 reflect pandemic-related restrictions that prevented in-person training.

5.1.3 General and Administrative Costs

General and administrative costs are comprised of internal and external costs required to support the overall operation and management of the Company.[70]

Table 5-9 provides a summary of the general and administrative costs for 2019 to 2025. Refer to Appendix C for a detailed year-over-year analysis for 2022 and the rate-setting period, along with a detailed comparison of actuals to forecast for 2019 to 2021.

TABLE 5-9
General and Administrative Costs ($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Customer Service	1,923	1,852	2,285	2,123	2,174	2,226	2,277
Finance	1,392	1,414	1,314	1,405	1,440	1,476	1,512
Corporate Communications	414	475	712	840	820	843	861
Information Technology	695	699	898	917	939	962	987
Regulation	1,065	1,020	1,141	1,305	1,331	1,357	1,385
Directors' Fees	365	390	413	523	536	550	563
General Property	692	770	787	809	830	851	872
Corporate Services	2,938	4,014	4,779	4,932	5,115	5,294	5,515
Total	**9,484**	**10,634**	**12,329**	**12,854**	**13,185**	**13,559**	**13,972**

Customer Service

This category provides for the customer service and meter reading functions. During the rate-setting period, costs are forecast to increase by an average of 2.4 per cent annually. In comparison, actual costs from 2019 to 2021 increased by an average of 9.8 per cent annually, which was lower than approved forecast and primarily reflect lower-than-expected employee vacancies in 2019.

The 2023 to 2025 forecasts reflect inflationary adjustments while non-labour costs have been reduced to reflect the 2019 and 2021 trend with respect to bad debt expense and damage claims.

[70] In Order UE09-02 the Commission disallowed, for the purpose of determining the Company's regulated revenue requirement, all Fortis Inc. head office administrative costs charged to Maritime Electric. Therefore, all costs presented in this section do not contain any Fortis Inc. administrative costs.

Finance

This category provides for the financial reporting and customer billing functions. During the rate-setting period, costs are forecast to increase by an average of 2.5 per cent annually. In comparison, actual costs from 2019 to 2021 decreased by an average of 2.7 per cent annually, which was driven by employee retirements and an employee on parental leave.

The 2023 to 2025 forecasts reflect historical actuals adjusted for inflation.

Corporate Communications

This category provides for all aspects of communicating with and disseminating information to customers and other stakeholders, and from 2021 includes costs associated with sustainability activities. During the rate-setting period, costs are forecast to increase by an average of approximately 0.9 per cent annually. In comparison, actual costs from 2019 to 2021 increased by an average of 32.3 per cent annually, driven by an additional employee position in 2021.

The forecasts for 2023 to 2025 are based on a normalization of historical costs adjusted for inflation. The 2023 non-labour forecast is lower than the prior year forecast reflecting a one-time climate change study to be completed in 2022.

Information Technology

This category includes costs associated with maintaining the Company's technology systems. During the rate-setting period, costs are forecast to increase by an average of 2.5 per cent annually. In comparison, actual costs from 2019 to 2021 increased by an average of 14.5 per cent annually, which was overall lower than approved forecasts.

The 2023 to 2025 forecasts reflect historical actuals adjusted for inflation.

Regulation

This category includes costs associated with regulatory filings. During the rate-setting period, costs are forecast to increase by an average of 2.0 per cent annually, which is slightly below inflation.[71] In comparison, actual costs from 2019 to 2021 increased by an average of 3.8 per cent annually, which was materially in line with approved forecasts.

[71] Inflation has not been applied to the annual forecasts of IRAC assessment fees.

Directors' Fees

This category includes fees paid to Maritime Electric's Board of Directors and related expenses. Directors' fees are reviewed periodically to ensure they remain competitive, enabling the Company to attract highly skilled individuals to serve on the board. During the rate-setting period, costs are forecast to increase by an average of 2.5 per cent annually, in line with inflation. In comparison, actual costs from 2019 to 2021 increased by an average of 6.4 per cent annually, which was lower than approved forecasts.

General Property

This category includes costs associated with the operation and maintenance of the Company's main office, district offices and substation buildings. During the rate-setting period, costs are forecast to increase by an average of 2.5 per cent annually, in line with inflation. In comparison, actual costs from 2019 to 2021 increased by an average of 6.7 per cent annually, as a result of pandemic-related activities.

Corporate Services

This category includes labour costs for the executive and senior management associated with: human resources; internal audit; health, safety and environment; system planning; administrative support; and other organizational expenses. During the rate-setting period, costs are forecast to increase by an average of 3.8 per cent annually, which reflects inflationary increases and the normal variability of these types of costs.

In comparison, actual costs from 2019 to 2021 increased by an average of 27.8 per cent annually, which was entirely due to variances in employee future benefit costs. Excluding the impact of employee future benefits costs, the remaining corporate services costs were flat over the 2019 to 2021 period.

5.1.4 Other Revenue

Table 5-10 provides a breakdown of other revenue for 2019 to 2025.

TABLE 5-10 Other Revenue ($000)							
	2019 Actual	**2020 Actual**	**2021 Actual**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
OATT Revenue	11,366	11,114	10,802	12,466	13,888	14,077	14,278
Miscellaneous Revenue	1,975	1,988	2,393	1,866	2,694	2,469	2,599
Rate of Return Adjustment	(3,509)	-	(238)	(506)	-	-	-
2020 Revenue Shortfall	-	3,006	(2,330)	(2,361)	(394)	-	-
Weather Normalization Reserve	(766)	363	1,427	-	-	-	-
Total	**9,066**	**16,471**	**12,054**	**11,465**	**16,188**	**16,546**	**16,877**

OATT Revenue

This category captures the revenue derived from charging the OATT to transmission users. OATT revenue reflects the current approved OATT rates up to June 30, 2022. It was assumed that the proposed OATT rates submitted on July 31, 2021 to the Commission for approval would become effective July 1, 2022.

Miscellaneous Revenue

Miscellaneous revenue includes late payment charges, connection fees, telecom attachment fees, accrued revenue and other.

Rate of Return Adjustment

This account, also referred to as RORA, captures any collections from customers in excess of the approved return on average common equity, which are subsequently refunded to customers.

In accordance with Order UE19-08, $3 million of the RORA recognized in 2019 was offset against the costs related to post-tropical storm Dorian, and the remaining $0.5 million was offset against the ECAM balance.

The RORA recognized in 2021 and forecast in 2022 is proposed to be refunded to customers in 2023 and 2024, as discussed in Section 5.3.2 of this Application.

2020 Revenue Shortfall

In accordance with Order UE20-06, the Company recognized revenue of $3.0 million in 2020 to accrue for the recovery of its 2020 revenue requirement. Customer rates effective January 1, 2021 were designed to recover the 2020 revenue shortfall from January 1, 2021 to February 28, 2022. As these customer rates continued past February 28, 2022, the Company forecasts an over-recovery of $2.1 million as of February 28, 2023, which is proposed to be refunded to customers over a 12-month period, as discussed in Section 5.3.3 of this Application.

Weather Normalization Reserve

This account captures the revenue impact of warmer- or colder-than-normal temperatures. During the rate-setting period, it is assumed that temperatures will be normal (i.e., consistent with the 10-year historical average), therefore no amounts are forecast for the Weather Normalization Reserve account. In comparison, actual temperatures for 2019 to 2021 did deviate from the 10-year historical average as demonstrated by the amounts in Table 5-10. The Weather Normalization Reserve account is forecast to have a balance recoverable from customers of $1.8 million as of February 28, 2023, which is discussed in Section 5.3.4 of this Application.

5.1.5 Depreciation and Amortization

Depreciation and amortization during the rate-setting period reflects the methodology and depreciation rates outlined in the Company's 2020 Depreciation Study.[72] In comparison, from 2019 to 2022 Maritime Electric's depreciation expense reflects the methodology and depreciation rates outlined in its 2017 Depreciation Study.[73] Refer to Appendix D for a detailed discussion of the 2020 Depreciation Study.

Table 5-11 summarizes the depreciation and amortization from 2019 to 2025.

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[72] In a letter dated June 28, 2021, the Commission approved the Company's request for an extension on the filing deadline for the 2020 Depreciation Study, which was filed on July 29, 2021.

[73] The 2017 Depreciation Study was approved by the Commission in Order UE19-08, which also directed Maritime Electric to file a new depreciation study, based on financial results up to December 31, 2020, no later than June 30, 2021.

TABLE 5-11 Depreciation and Amortization ($000)							
	2019 Actual	**2020 Actual**	**2021 Actual**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
Fixed Assets	23,337	28,778	26,359	24,116	26,786	28,462	30,493
CTGS Reserve Variance	-	-	-	-	2,135	2,135	2,135
Provincial Debt Repayment – Under Collection	-	-	-	-	80	95	95
Point Lepreau Write-Down	94	94	94	93	93	93	93
DSM Program	157	573	149	-	-	-	-
Total	**23,588**	**29,445**	**26,602**	**24,209**	**29,094**	**30,785**	**32,816**

Table 5-12 shows that the increase in depreciation and amortization over the rate-setting period is associated with the implementation of new depreciation rates, in accordance with the 2020 Depreciation Study, and forecast capital additions.

TABLE 5-12 Fixed Asset Depreciation ($000)			
	2023 Forecast	**2024 Forecast**	**2025 Forecast**
Depreciation on forecast balance of fixed assets at January 2023	24,942	24,942	24,942
Depreciation due to implementation of 2020 Depreciation Study rates	1,153	1,153	1,153
Depreciation on capital additions during the rate-setting period	692	2,367	4,398
Total	**26,787**	**28,462**	**30,493**

The Company proposes that the depreciation rates recommended in the 2020 Depreciation Study, with the exception of the rates pertaining to Charlottetown Steam Plant, be adopted effective January 1, 2023.

The amortization of the CTGS reserve variance is discussed in detail in Section 5.3.5 of this Application, the amortization of an under collection balance related to the provincial debt repayment costs is discussed in Section 5.3.6, and the amortization of a Point Lepreau write-down is discussed in Section 5.3.7.

The DSM Program costs, with the exception of 2020, relate entirely to the Company's 2015 to 2020 DSM that was approved in Order UE15-02. In the last GRA, the Company did not seek approval for the continuance of its DSM Program as the PEIEC assumed responsibility for DSM activities as a result of amendments to the *Electric Power Act.*

The DSM Program costs for 2020 includes $446,000 that was paid to the PEIEC in accordance with Order UE20-06.

5.1.6 Finance Charges

Table 5-13 summarizes the Company's finance charges for 2019 to 2025.

TABLE 5-13
Finance Charges ($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Long-Term Interest	12,442	12,442	12,535	13,801	13,801	14,039	15,221
Short-Term Interest[74]	920	706	501	265	656	1,164	302
Amortization of Financing Costs	13	14	15	21	22	24	31
Allowance for Funds Used During Construction	(474)	(444)	(548)	(570)	(682)	(950)	(961)
Total	**12,901**	**12,718**	**12,503**	**13,517**	**13,797**	**14,277**	**14,593**

Long-Term Interest

The Company issues first mortgage bonds ("long-term debt") to primarily fund capital investment. The Company is required to obtain regulatory approval prior to issuing any long-term debt.

Table 5-14 details the Company's long-term interest costs for 2019 to 2025.

[74] Short-term interest in 2019 and 2020 includes approximately $0.7 million and $0.4 million, respectively, related to the interest accrued to customers on the RORA account and the long-term income tax receivable account related to the Capital Asset Review.

TABLE 5-14 Long-Term Interest ($000)								
Issue Date	**Principal Amount**	**2019 Actual**	**2020 Actual**	**2021 Actual**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
1996	20,000	1,784	1,784	1,784	1,784	1,784	1,784	1,784
1997	15,000	1,294	1,294	1,294	1,294	1,294	1,294	1,294
2000	15,000	1,135	1,135	1,135	1,135	1,135	1,135	946
2008	60,000	3,632	3,632	3,632	3,632	3,632	3,632	3,632
2011	30,000	1,475	1,475	1,475	1,475	1,475	1,475	1,475
2016	40,000	1,463	1,463	1,463	1,463	1,463	1,463	1,463
2018	40,000	1,659	1,659	1,659	1,659	1,659	1,659	1,659
2021	40,000	-	-	93	1,359	1,359	1,359	1,359
2024	40,000	-	-	-	-	-	238	1,430
2025	30,000	-	-	-	-	-	-	179
Total	**330,000**	**12,442**	**12,442**	**12,535**	**13,801**	**13,801**	**14,039**	**15,221**

During the rate-setting period, the Company expects to issue long-term debt of $40 million in 2024 and $30 million in 2025. Both issuances are forecast to have a term of 40 years and an interest rate of 3.58 per cent. The long-term debt issue in 2025 will be partially used to refinance the $15 million maturing in November 2025, which was originally issued in 2000 at an interest rate of 7.57 per cent.

Maritime Electric's average cost of long-term debt from 2019 to 2025 is expected to decline by 0.75 per cent, which primarily reflects replacing the $15 million maturing debt with debt at a lower interest rate.

Short-Term Interest

The Company maintains a $50.0 million committed unsecured credit facility with Scotiabank to meet its short-term borrowing requirements. The Company's short-term financing requirements include energy-related costs, operating costs, inventory purchases, payroll costs, and tax installments, amongst other things.

The Company also uses credit facility borrowings to temporarily finance its capital investments until long-term debt is issued. Therefore, short-term borrowings and the related interest costs are typically highest just before long-term debt is issued.

Under the terms of the credit facility agreement, the Company can borrow using a prime loan or a banker's acceptances ("BA"). The Company typically borrows using a BA as it has a lower interest rate. At certain times, Maritime Electric benefits from the combined borrowing power of the Fortis group of companies as it is able to borrow funds at a lower interest rate than it would be able to negotiate on its own.

Amortization of Financing Costs

Maritime Electric uses the effective interest method of accounting for the costs associated with issuing debt. Under the effective interest method, these costs are recorded as a deferred charge and amortized over the term of the debt in accordance with Order UE06-05.

During the rate-setting period, the Company expects to issue long-term debt of $40 million in 2024 and $30.0 million in 2025 and estimates the associated issue costs will be $400 thousand and $300 thousand, respectively.

Allowance for Funds Using During Construction

As is common practice in the utility industry, Maritime Electric provides for the cost of financing capital additions during construction, known as an allowance for funds used during construction ("AFUDC"). The AFUDC rate reflects the cost of debt and equity financing, which is approved by the Commission through the annual capital budget application process and is amortized over the service life of the related assets.

5.1.7 Income Taxes

Maritime Electric uses the future income taxes method of accounting for income taxes. Under this method, future or deferred income taxes are recognized for temporary differences between the tax and accounting basis of assets and liabilities using the enacted or substantially enacted income tax rates for the years in which the differences are expected to reverse. Maritime Electric maximizes its tax deductions to minimize cash taxes and the impact on customer rates.

Table 5-15 shows the income taxes and effective income tax rates for 2019 to 2025.

TABLE 5-15 Income Taxes							
	2019 Actual	**2020 Actual**	**2021 Actual**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
Income taxes ($000)	6,483	6,666	6,970	7,429	8,459	8,994	9,538
Effective income tax rate (%)[75]	31.3	30.5	32.0	31.2	31.2	31.2	31.2

5.1.8 Return

Table 5-16 shows Maritime Electric's achieved regulated return for 2019 to 2021 and proposed return for 2023 to 2025.

TABLE 5-16 Return							
	2019 Actual	**2020 Actual**	**2021 Actual**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
Return ($000)	14,263	14,673	15,329	16,364	18,660	19,850	21,066
ROE (%)	9.35	9.30	9.35	9.35	9.95	9.95	9.95

For 2019 to 2022 Maritime Electric's approved ROE is 9.35 per cent and, as discussed in Section 5.2 of this Application, the proposed ROE for the rate-setting period is 9.95 per cent.

As Table 5-16 demonstrates, Maritime Electric is not guaranteed to earn its allowed ROE. The impact of the pandemic, which reduced General Service and Industrial sales and increased certain operating costs, caused Maritime Electric to only earn a regulated return of 9.30 per cent in 2020.

5.1.9 Credit Metrics

Maritime Electric maintains an investment grade credit rating from an independent rating agency: Standard and Poor's Financial Services LLC ("S&P"), which is discussed further in Section 5.2.2 of this Application.[76] A review of the Company's credit metrics forms part of S&P's annual credit rating assessment.

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75 Effective income tax rate in 2020 reflects a tax reduction associated with a loss carryback, which was subsequently denied by the Canadian Revenue Agency. The reversal of the loss carryback was recognized in 2021, resulting in a higher tax rate in 2021.

76 The most recent S&P credit rating report is provided as Appendix G.

S&P continues to consider Maritime Electric's geographic area and small size a significant risk along with the potential for political interference. The primary credit metrics used by S&P are cash flow debt coverage and interest coverage, both of which are presented in Tables 5-18 and 5-19. S&P noted in their annual credit rating assessment that the Company's credit rating could be downgraded if its financial metrics weaken, including a decline in the cash flow debt coverage to below 15 per cent.

Under existing customer rates (i.e., assuming the proposed rate increase is not approved), Maritime Electric's credit metrics, as shown in Table 5-17, are expected to decline significantly.

TABLE 5-17
Credit Metrics – Existing Customer Rates

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Cash Flow Debt Coverage (%)	17.9	18.9	16.8	16.4	13.7	10.2	7.5
Interest Coverage (times)	2.4	2.4	2.5	2.6	2.0	1.5	1.0
Debt to Equity Ratio[77] (%)	39.5	39.3	39.1	40.0	38.2	35.2	31.1
Regulated Return (%)	9.35	9.30	9.35	9.35	5.87	2.93	0.05

Maritime Electric's financial outlook, combined with its business risk, can affect the Company's ability to maintain the current credit rating and access capital markets at reasonable costs. Table 5-18 shows the credits metrics under the proposed customer rates.

TABLE 5-18
Credit Metrics – Proposed Customer Rates

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Cash Flow Debt Coverage (%)	17.9	18.9	16.8	16.4	18.1	18.0	18.2
Interest Coverage (times)	2.4	2.4	2.5	2.6	2.8	2.8	2.9
Debt to Equity Ratio (%)	39.5	39.3	39.1	40.0	40.0	40.0	40.0
Regulated Return (%)	9.35	9.30	9.35	9.35	9.95	9.95	9.95

[77] The *Electric Power Act* requires Maritime Electric to maintain at all times its common equity at not less than 35 per cent.

5.2 Cost of Capital

In this Application, the Commission will consider Maritime Electric's cost of capital for the rate-setting period of 2023 to 2025. The Company engaged Concentric Energy Advisors, Inc. ("Concentric") to provide an estimate of Maritime Electric's cost of capital. The expert evidence filed with this Application as Appendix F indicates a fair return for Maritime Electric comprises: (i) a capital structure consisting of 40 per cent common equity and 60 per cent debt; and (ii) an allowed ROE of 9.95 per cent.

In determining a fair return, the Commission applies principles prescribed by the *Electric Power Act* and the Fair Return Standard. A fair return is generally accepted to be one that is: (i) commensurate with returns and investments of similar risk; (ii) sufficient to ensure the utility's financial integrity; and (iii) sufficient to attract necessary capital. Therefore, a critical component in determining a fair return is an assessment of the Company's overall risk profile, including an assessment of capital market conditions as well as business and financial risk.

Other customary tools in evaluating an appropriate cost of capital are the use of financial models and a comparison to other utilities. This section presents the results of the financial models used by Concentric along with an interpretation of those results. Finally, this section presents a comparison of the Company's proposed cost of capital to other Canadian utilities.

Overall, the evidence presented in this section demonstrates that the risks facing Maritime Electric support a higher cost of capital.

5.2.1 Fair Return Standard

The Fair Return Standard is a fundamental principle for both the regulator and regulated company that was established by the Supreme Court of Canada[78] and has been supported by the Commission in previous orders.[79]

The application of the Fair Return Standard ensures that utilities are in a position to: (i) meet their

[78] The concept of a "fair return" for a regulated company was established by the Supreme Court of Canada in *Northwestern Utilities v. City of Edmonton (1929)* S.C.R. 186.

[79] The Commission referenced a "fair return" in UE09-02 paragraphs 57 to 60 and in UE19-08 paragraph 93.

customers' service needs at a reasonable cost; (ii) attract investment capital at a reasonable cost under all market conditions; (iii) earn a fair and reasonable return on previously invested capital; and (iv) be financially sustainable under ongoing and changing business risks.

In addition to being fair to the utility, adhering to the Fair Return Standard is beneficial for customers who can continue to obtain utility service from a utility operating on a financially strong and sustainable basis.

5.2.2 Risk Assessment

Maritime Electric's cost of capital is the rate of return investors could expect to earn if they invested in securities of equal risk. Concentric examines capital market conditions along with Maritime Electric's business and financial risks, which together are the primary elements of risk that investors consider when establishing their return requirements. The following section summarizes Concentric's assessment of Maritime Electric's risk.

Capital Market Conditions

An important aspect of the Fair Return Standard is the utility's ability to attract investment capital at a reasonable cost under all market conditions. Applying this standard to Maritime Electric involves examining the market conditions under which the Company seeks to attract investment.[80] Concentric discusses a number of factors that indicate capital markets conditions are putting upward pressure on the returns investors need to compensate for the risk they assume.[81]

Since Maritime Electric filed its last GRA in 2018, capital markets have experienced a volatile period associated with the onset of the pandemic in 2020. More recently, the conflict between Russia and Ukraine is causing market volatility for which the outcome is uncertain.

Economies in both Canada and the United States ("U.S.") sharply contracted in 2020 and began to rebound in 2021. In both Canada and the U.S., gross domestic product ("GDP") growth shrank at the onset of the pandemic and has continuously improved since. Likewise, unemployment rates in Canada and the U.S. peaked in April/May of 2020 and have improved gradually since.

[80] Maritime Electric seeks investment with the issuance of first mortgage bonds and equity investment via its parent company.

[81] Section III of the Concentric's Cost of Capital Report provides a detailed review of the economic and capital market conditions that impact the Company's cost of capital.

The market volatility experienced since the onset of the pandemic resulted in the central banks and federal governments in both Canada and the U.S. instituting extraordinary policy measures to stabilize the financial system, support economic growth and provide additional unemployment benefits to those in industries most affected by COVID-19. The extraordinary policy measures taken resulted in a steep drop in interest rates on government and corporate bonds. However, in March 2022, the Bank of Canada increased the overnight rate by 25 basis points for the first time since the start of an aggressive monetary policy that was in response to COVID-19, and increased the overnight rate by 50 basis points in both April and June. The Bank of Canada has signalled that it may continue to increase the overnight rate to combat inflation.

As world economies emerge from the effects of the pandemic, global and domestic supply chain disruptions are continuing to exert upward pressure on prices. Inflationary pressure has increased in both Canada and the U.S., in recent months, and geopolitical events, such as the conflict between Russia and Ukraine, have caused continued volatility, as oil prices have surged and global markets have declined significantly from near all-time highs.

Historically, a comparison has been made between interest rates on government or corporate bonds and utility returns, suggesting that the risk and return on these investment opportunities should be comparable. Concentric's assessment of capital market conditions challenges this traditional comparison. Evidence presented by Concentric highlights that as investors expect stronger economic growth and higher inflation, which is generally expected during the rate-setting period, that higher returns will be required by investors for them to invest in long-term government bonds or similar risk investments, such as utilities.

Furthermore, stock prices in both Canada and the U.S. fell sharply in early 2020 as investors reacted to the global pandemic and a sharp decline in crude oil prices, resulting in increased volatility in equity markets. The extraordinary policy measures taken in both Canada and the U.S. are having the desired impact on equity markets and volatility has somewhat declined recently, yet there is ongoing uncertainty in financial markets, influencing the returns required by investors.

While economies in Canada and the U.S. have rebounded from the impacts of the pandemic, Concentric concludes that *"uncertainty and volatility in financial markets have caused equity investors to require a higher rate of return to compensate them for the additional uncertainty and* *risk created by the COVID-19 pandemic and the corresponding economic fallout. Longer term, the utility industry faces complex structural challenges associated with climate change, decarbonization, cybersecurity, grid modernization and shifting consumer preferences amid a flat overall consumption profile."*[82]

Therefore, overall market conditions support an increase in the Company's cost of capital in order to access investment capital under all market conditions.

Business Risk

Business risk for a regulated utility encompasses both operational risk (e.g., size of service territory and geographical diversity, economy of service territory, weather conditions, etc.) and regulatory risk (e.g., opportunity for timely recovery of prudently-incurred costs). Business risk informs a utility's cost of capital because it impacts the likelihood that the utility will be able to earn a fair return on its invested capital.

Concentric notes a number of factors that increase its assessment of Maritime Electric's risk: (i) size; (ii) economic conditions on PEI; (iii) operating risks; (iv) regulatory deferrals; and (v) political and regulatory uncertainty.[83] Each element of risk causes investors to require a higher cost of equity to compensate for that risk.

The Company's small size exposes it to a greater risk that customer demand could decrease significantly due to a major employer, industry or the Provincial economy experiencing a downturn or deciding to relocate. In its May 2021 credit report, S&P noted that its assessment of Maritime Electric's business risk is negatively impacted by the Company's small customer base and lack of geographical and regulatory diversity.[84]

Over the long term, GDP growth and household disposable income on PEI are projected to be weaker than Canada overall, while growth in the labour force and housing starts are projected to be stronger.

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[82] Section III of the Concentric's Cost of Capital Report provides a detailed review of the economic and capital market conditions that impact the Company's cost of capital.
[83] Section VI of the Concentric Report provides a detailed assessment of the Company's business and financial risk.
[84] S&P's report is provided as Appendix G.

Certain operational aspects increase Maritime Electric's business risk, including its reliance on off-Island energy and capacity resources from NB Power, limited on-Island backup generation, exposure to weather-related service disruptions, and reliance on intermittent wind and solar generation facilities that are not controlled by the Company.

The Company's ability to recover operating costs that are beyond the Company's control and/or are significant in magnitude impacts the assessment of risk. Concentric noted that Maritime Electric does not have a storm-related deferral account, despite operating in a service territory characterized by severe wind and ice storms, which heightens the Company's risk profile.

The active role of government, as demonstrated by past legislative changes that reduced the Company's allowed equity ratio, contributes to a higher degree of political/regulatory risk for the Company. Past legislative changes have also provided the government with the option to own future generation on PEI, and gave the government responsibility for DSM and energy efficiency programs. Even more recently, the Provincial Government's Net Zero Report will have an impact on Maritime Electric that is yet unknowm. This risk of political interference negatively impacts both S&P and Concentric's assessment of the Company's risk profile.

Concentric's overall assessment is that "*Maritime Electric continues to have many of the same business and operating risks as in prior GRA filings"*. Furthermore, in the most recent GRA when the Commission approved the Company's ROE remain at 9.35 per cent for 2019 to 2021, it noted that *"other changes being made in this Order may have the effect of slightly increasing the Company's risk".*[85]

Financial Risk

Financial risk primarily relates to the risk associated with the way in which a company finances its business, as evidenced by the relative percentages of debt and equity in its capital structure. To the extent a company is more highly leveraged, it requires higher net income to cover its fixed interest obligations, which must be paid before there is any net income for shareholders. Financial risk is assessed by credit rating agencies and generally measured via credit metrics.

[85] Order UE19-08 paragraph 121.

A corporate credit rating is a measure of a company's overall credit worthiness, based on an independent analytical review of the company's capital structure, earnings, cash flows, financial position along with an analysis of company-specific and industry-related issues. Maritime Electric maintains an investment grade credit rating from S&P. The Company's most recent report by S&P ("S&P Report"), dated May 11, 2021, is included as Appendix G.

As noted in the S&P Report, the Company's corporate credit rating is BBB+ (stable outlook), which is two notches above the minimum rating considered as investment grade, while its long-term debt credit rating is A. Maritime Electric's credit ratings are based on its stand-alone credit profile, which are not impacted by being a wholly owned subsidiary of Fortis Inc.

The S&P Report noted that its assessment of Maritime Electric's financial risk is "significant" based on an expectation of stable and predictable cash flows resulting in a ratio of funds from operations ("FFO") to debt of 16 to 17 per cent. The S&P Report noted that the Company's rating could be downgraded if its FFO to debt were consistently below 15 per cent.

The FFO interest coverage is another key credit metric that measures the Company's ability to meet its debt obligations. It is the Company's view that an interest coverage ratio greater than 2.0 times is an appropriate target given the Company's relatively weaker financial risk profile and the need to compete for sources of financing.

Another aspect of attracting investment capital is the ability to pay dividends. The inability to pay dividends on a consistent basis may result in considerably more restrictive covenants for new debt issues, limitations on the term for which investors are prepared to lend, and ultimately a higher cost of financing. The Company's regular payment of dividends also assists in maintaining an appropriate balance between debt and equity in order to meet the Company's target capital structure and comply with the legislative requirements of the *Electric Power Act*.

The Company is forecasting the continued payment of both regulated and non-regulated dividends over the rate-setting period. Regulated dividends represent amounts paid out of the equity retained in the Company to support the regulated operations and upon which the Company is allowed a regulated return. Non-regulated dividends arise from a non-regulated equity contribution by the shareholder through a tax sharing agreement between the companies. As a non-regulated component of equity, Maritime Electric does not seek to earn a regulated return on this amount and, as a result, there is no revenue requirement to be recovered from customers. Since the shareholder does not earn a return on this equity, it has requested that the non-regulated equity be returned annually through a dividend payment.

Table 5-19 shows Maritime Electric's actual and forecast dividend payments for the period 2019 to 2025.

TABLE 5-19
Dividends ($ millions)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Regulated	8,500	7,500	8,675	2,500	7,000	6,000	9,500
Non-Regulated	-	213	213	213	213	213	213
Total	**8,500**	**7,713**	**8,888**	**2,713**	**7,213**	**6,213**	**9,713**

5.2.3 Financial Models

In determining the appropriate cost of equity range for Maritime Electric, Concentric used both Canadian and US proxy groups to develop and estimate utility cost of equity using a variety of methodologies (Discounted Cash Flow ("DCF") method, Capital Asset Pricing Model ("CAPM"), and Risk Premium method), as is industry practice.[86] As discussed by Concentric, each methodology presents a different perspective and each has its own limitations. As such, conclusions should not be based on a single methodology without corroboration from other approaches.

Table 5-20 shows that Concentric's analysis of the proxy groups produced a cost of equity range of 8.96 per cent to 12.08 per cent, and an overall average of 10.4 per cent. The Company's proposed ROE of 9.95 per cent is lower than the average of the proxy group results.

[86] Refer to Concentric's Report Section V for a detailed discussion of the financial models and their results.

TABLE 5-20 Proxy Group Cost of Equity Results (%)				
	Canadian Regulated Utilities	**US Electric Utilities**	**North American Electric Utilities**	**Average**
Constant Growth DCF	12.08	9.77	10.12	10.7
Multi-Stage DCF	10.48	8.96	9.21	9.6
CAPM	10.35	10.79	10.48	10.5
Risk Premium	-	10.01	10.01	10.0
Average	**11.00**	**10.00**	**10.10**	**10.4**

5.2.4 Comparison to Other Canadian Utilities

In addition to the financial models and proxy groups discussed above, it is useful to compare the cost of capital proposed by Maritime Electric to other Canadian utilities. Table 5-21 calculates the weighted cost of capital of other Canadian utilities in comparison to Maritime Electric, taking into consideration the upper ROE limit they are incentivized to achieve and their allowed equity ratio.

TABLE 5-21 Weighted Equity Returns Based on Upper Bound ROE (%)					
	Allowed ROE A	**Deadband B**	**Upper Bound ROE C = A + B**	**Equity Ratio D**	**Upper Bound Weighted Cost of Capital E = C x D**
Newfoundland Power	8.50	0.50	9.00	45.0	4.05
Alberta Electric Utilities – one year	8.50	5.00	13.50	37.0	5.00
Alberta Electric Utilities – two years	8.50	3.00	11.50	37.0	4.26
Ontario Electric Utility Distributors	8.34	3.00	11.34	40.0	4.54
FortisBC Energy Inc. (gas)[87]	8.75	1.50	10.25	38.5	3.95
FortisBC Inc. (electric)	9.15	1.50	10.65	40.0	4.26
Maritime Electric - current	**9.35**	**-**	**9.35**	**40.0**	**3.74**
Maritime Electric - proposes	**9.95**	**-**	**9.95**	**40.0**	**3.98**

Table 5-21 demonstrates that Maritime Electric's proposed ROE of 9.95 per cent results in a cost of capital that is at the lower end of what can be achieved by other Canadian utilities. In particular, Maritime Electric's proposed weighted cost of capital is only 3 basis points above the upper bound weighted cost of capital of FortisBC Energy Inc. The Commission has stated that it *"views*

[87] FortisBC Energy Inc.'s ROE is considered the British Columbia Utilities Commission benchmark for utilities in British Columbia.

Maritime Electric as higher risk than the benchmark BC utility and FortisBC due to a variety of factors such as utility size, nature of operations, economic climate within which it operates, and regulatory risk factors".[88]

Conclusion

Considering all the evidence presented, Concentric's opinion is that *"the proposed 9.95 per cent ROE and 40.0 per cent equity ratio taken together are reasonable, and provide the Company with the financial strength required to meet its debt service obligations while providing a fair return to its shareholders".*

The Company proposes that the target average common equity component of its capital structure remain at 40 per cent for purposes of determining the annual revenue requirement in customer rates related to the allowable return on average common equity, and the ROE be set at 9.95 per cent.

5.2.5 Regulatory Framework

Maritime Electric is required to invest capital in the electrical system to ensure the continued delivery of reliable service to customers. Each year, the Company's capital expenditures for the subsequent year are considered and approved by the Commission. This capital investment is funded with a combination of common equity and debt financing. The Company's cost of capital depends on: (i) the amount of common equity and debt used to finance capital investment; (ii) the rate of return on common equity; and (iii) the interest rates on outstanding debt.

Interest rates on the Company's debt are determined by financial markets. Interest on short-term debt is primarily based on prime lending rates. Interest on long-term debt is determined by capital markets at the time the debt is issued. Debt rating agencies, such as S&P, facilitate financial markets by providing credit ratings that are indicative of the risk of the investment.

Maritime Electric has held investment grade ratings from S&P since 2004.[89] The Company's capital structure and ROE are measures of financial risk considered by credit rating agencies in determining an appropriate credit rating for Maritime Electric. Capital structure, ROE, and credit

[88] Order UE10-03 paragraph 101.
[89] Section VI - D of Concentric's Report.

ratings are therefore interrelated.

The *Electric Power Act*, Section 12.1, requires Maritime Electric to:

> *"(a) maintain at all times not less than 35 per cent of its capital invested in the power system in the form of common equity; and (b) ensure that, for the year, not more than 40 per cent of its capital is invested in the power system in the form of common equity."*

To ensure that the Company's capital structure remains flexible and able to adapt to changing market conditions, the target common equity component of the Company's capital structure throughout the year will fluctuate between 39 and 40 per cent. The Company proposes that the target average common equity component of its capital structure be set at 40 per cent for purposes of determining the annual revenue requirement in customer rates related to the allowable return on average common equity.

Table 5-22 shows the Company's average capital structure for the period 2019 to 2025.

TABLE 5-22
Average Regulated Capital Structure (%)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Debt	60.7	60.8	61.0	60.4	60.0	60.0	60.0
Equity	39.3	39.2	39.0	39.6	40.0	40.0	40.0
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

5.3 Regulatory Deferrals and Amortizations

Regulatory deferrals are important mechanisms in the utility ratemaking framework. A regulatory deferral allows a utility to defer costs or revenue on the balance sheet to be recovered from or returned to customers in a future period, subject to the regulator's approval.

These deferrals are an interim ratemaking tool designed to reduce regulatory lag and allow the regulator time to assess whether such costs or revenue should be recovered from or returned to customers. They also help to ensure stable and predictable rates for customers while ensuring that the utility's financial position is not unreasonably harmed or helped by events outside of its control.

When determining the period over which the deferred amount is recovered from or returned to customers (i.e., amortizing the deferral), utilities and regulators seek an appropriate balance between two regulatory principles, intergenerational equity and rate stability, which are often inconsistent with each other. The former indicates that deferred amounts should be reflected in rates as soon as is reasonable to ensure the customers who pay for the costs will be the same as those for whom the costs were incurred. While the latter indicates that customer rates should remain stable and predictable, with any sharp rate changes being smoothed over time. When a deferred amount is significant, the intergenerational equity principal would result in a sharp rate change while the rate stability principal would result in a gradual longer term rate change.

Maritime Electric has a limited number of regulatory deferrals, which are discussed in detail as follows.

5.3.1 Energy Cost Adjustment Mechanism

The Energy Cost Adjustment Mechanism ("ECAM"), as approved by the Commission, is a mechanism that ensures the timely collection of prudently incurred energy supply costs and allows for the deferral of unplanned fluctuations in energy supply costs during a rate-setting period.

At the beginning of a rate-setting period, the basic energy charge included in customer rates reflects a forecast of annual energy supply costs based on the Base Rate Cost, as defined in the ECAM and approved by the Commission. As actual energy supply costs incurred by Maritime Electric differ from the Base Rate Cost, the difference is deferred in the ECAM account to be collected from or refunded to customers in a future period via an ECAM Rate Adjustment applied to customers' bills, as approved by the Commission.

In June 2020 the Company filed with the Commission a comprehensive review of the energy supply accounts included in the ECAM. In Order UE21-05, the Commission approved the continued operation of the ECAM, including the Company's proposed revisions to the accounts to be included in the ECAM. Table 5-25 summarizes the costs to be included in the ECAM base rate over the GRA period in accordance with Order UE21-05.

Also in Order UE21-05, the Commission did not approve the automatic annual resetting of the ECAM rate rider on March 31 each year partly because *“there may reasonably be greater annual fluctuations and less predictability in electric rates, which is not in the best interest of ratepayers”*.

Proposed ECAM Rate Adjustment on March 1, 2023

In December 2021 the Company applied for an ECAM Rate Adjustment to be applied to customers’ bills to address an ECAM balance that had increased to $5.6 million throughout 2021, primarily due to three unplanned outages at Point Lepreau. In Order UE22-01, the Commission approved the Company’s request of an ECAM Rate Adjustment to be applied to customers’ bills of $0.00402 per kWh effective March 1, 2022 to February 28, 2023 or until otherwise approved by the Commission. This rate adjustment was based on the approved formula set out in Section N-0 of the Company’s Rates and General Rules and Regulations.

For 2022 the Company is forecasting a deferral of energy supply costs of $5.8 million, due to a Point Lepreau outage in 2022. The current approved base rate of $0.09244 per kWh was based on forecast energy supply costs for 2021, which did not include the impact of any planned outages in 2022. Actual energy supply costs incurred in 2022 will include replacement energy related to the planned outage and will therefore be higher than the forecast costs used to set the Base Rate Cost for 2021. The resulting increase in purchased and produced electricity costs will be appropriately deferred in the ECAM account, as summarized in Table 5-23.

TABLE 5-23 Energy Costs Deferred to ECAM January 1 to December 31, 2022		
Forecast Net Purchased and Produced Energy (kWh)	A	1,504,198,113
ECAM Base Rate ($/kWh)	B	0.09244
Total Base Energy Costs Recovered Thru Basic Rates ($)	C = A X B	139,048,074
Forecast Energy Costs Applicable to ECAM ($)	D	144,893,941
2022 Energy Costs Deferred to ECAM ($)	**E = D - C**	**5,845,867**

ECAM is currently designed to facilitate its balance being recovered from, or refunded to, customers within a two-year period. Section N-0 of the Company’s Rates and General Rules and Regulations specifies the formula for collection or refund of the ECAM as follows:

The ECAM Rate Adjustment applied to Customers' bills shall be calculated as follows and applied to Customers' bills for not less than twelve months unless otherwise ordered by the Commission.

6. *Determine the total of the excess (or deficiency) costs on the Balance Sheet at the end of the third month proceeding the month in which the ECAM rate will be applied.*
7. *Determine the forecast total kilowatt hour sales for the twelve month period commencing with the month in which the ECAM rate will be applied.*
8. *Divide the amount calculated in (6) above by the amount calculated in (7) above to determine the ECAM rate adjustment required in cents per kilowatt hour sold and which will be applied to Customers' bills. Rate adjustment shall be calculated to the nearest three decimal places (five decimal places on the dollar).*

Based on the above formula, the current ECAM Rate Adjustment of $0.00402 per kWh needs to be increased, effective March 1, 2023, as calculated in Table 5-24.

TABLE 5-24 Proposed ECAM Rate Adjustment to Customers' Bills Effective March 1, 2023 to February 29, 2024		
Forecast ECAM Balance, December 31, 2022[90] ($)	A	6,791,071
Forecast Sales - March 1, 2022 to February 28, 2023 (kWh)	B	1,396,277,700
Proposed March 1, 2023 ECAM Rate Adjustment ($)	C = A/B	**0.00486**

Proposed ECAM Base Rate

As mentioned above, the basic energy charge included in customer rates reflects a forecast of annual energy supply costs based on the Base Rate Cost, as defined in the ECAM and approved by the Commission.

Table 5-25 provides the calculation of the ECAM Base Rate for each year in the rate-setting period, and reflects the annual energy supply costs to be excluded from ECAM under Order UE21-05.

[90] As per the terms of the ECAM, the ECAM Rate Adjustment is calculated based on the ECAM balance two months prior. The ECAM balance at December 31, 2022 includes an uncollected balance of $1.0 million related to 2021 ECAM transactions and the $5.8 million from Table 5-26.

TABLE 5-25 ECAM Base Rate Effective March 1 - Scenario 1 ($000, except GWh and $/kWh)				
ECAM Components:		2023 Forecast	2024 Forecast	2025 Forecast
Point Lepreau Energy		25,481	24,661	25,647
Renewable Energy		26,635	37,187	50,637
Purchased Energy and Transmission from NB Power		83,855	79,030	67,268
Generation Operating Costs		2,125	2,156	2,543
Generation Fuel Costs		976	1,254	1,387
ECC Costs		1,106	1,154	1,206
Interconnection Costs		4,605	4,631	4,653
Provincial Debt Repayment Costs		4,103	5,411	5,457
Subtotal – Gross Energy Supply Costs		**148,886**	**155,484**	**158,798**
Less: UE21-05 Costs Excluded from ECAM		(8,347)	(10,483)	(10,999)
Energy Supply Costs Attributable to ECAM	**A**	**140,539**	**145,001**	**147,799**
Net Purchased and Produced (GWh)	**B**	**1,498.7**	**1,517.4**	**1,537.6**
ECAM Base Rate ($/kWh)	**C = A/B**	**0.09377**	**0.09556**	**0.09612**

The resulting ECAM Base Rate multiplied by the net purchased and produced energy becomes the annual energy supply costs recognized in the income statement for the year if no further adjustments to the ECAM Base Rate are made. The ECAM Base Rate combined with any ECAM Rate Adjustment becomes the energy supply cost charged to customers through the revenue requirement.

Recovering the forecast 2022 ECAM balance from customers over a one-year period, from March 1, 2023, together with the ECAM Base Rate, as calculated in Table 5-26 above, will result in an annual customer cost increase of 4.8 per cent in 2023 followed by rate increases of 0.9 per cent in 2024 and 2.0 per cent in 2025. Such rate volatility contradicts the regulatory principle of rate stability.

To facilitate more stable and predictable rate increases for customers over the rate-setting period, the Company proposes that some energy supply costs be deferred from the ECAM Base Rate and instead be collected later in the rate-setting period via the ECAM Rate Adjustment. The proposed ECAM Base Rates are shown in Table 5-26 and the proposed ECAM Rate Adjustments are shown in Table 5-27.

TABLE 5-26 ECAM Base Rate Effective March 1 ($/kWh) Scenario 2				
		2023 Forecast	2024 Forecast	2025 Forecast
ECAM Base Rate	C from Table 5-26	0.09377	0.09556	0.09612
Adjustment to Stablize Rates	D	(0.00317)	(0.00186)	-
ECAM Base Rate	**E = C + D**	**0.09060**	**0.09370**	**0.09612**

Adjusting the ECAM Base Rate as proposed in Table 5-26 will result in deferring energy supply costs of approximately $4.2 million from 2023 to be collected through the ECAM Rate Adjustment beginning on March 1, 2024 and approximately $3.7 million from 2024 to be collected through the ECAM Rate Adjustment beginning on March 1, 2025.

To collect the energy supply costs deferred in each year, the Company proposes the ECAM Rate Adjustments to customers' bills effective on March 1 of each year of the rate-setting period as set out in Table 5-27.

TABLE 5-27 Proposed ECAM Rate Adjustment to Customers' Bills Effective March 1				
		2023	2024	2025
Forecast ECAM Balance, December 31 of Prior Year ($000)	A	6,791	4,482	3,282
Forecast Sales - March 1 to February 28 (GWh)	B	1,396.3	1,416.7	1,436.1
Proposed March 1 ECAM Rate Adjustment - $/kWh (rounded)	**C = A/B**	**0.00486**	**0.00316**	**0.00229**

The resulting impact allows for a more stable average increase in customer rates of approximately 3.0 per cent for each year of the rate-setting period.[91]

Summary of ECAM Account Activity

In Order UE20-06, the Commission directed the Company to apply the December 31, 2020 balance in the ECAM account to the balance of RORA, hence the opening balance on January 1, 2021 was nil. Table 5-28 provides a summary continuity schedule of the ECAM account since

[91] Rate based on a benchmark customer as defined in Table 3-2 in Section 3.2.2 of this Application.

January 1, 2021 reflecting actual ECAM adjustments to December 31, 2021 and expected activity from 2022 to 2025 based on the proposals in this Application.

TABLE 5-28
Summary of Annual Activity in ECAM ($000)

		2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Total Energy Supply Costs by Source	A	138,545	146,030	148,886	155,484	158,798
Energy Costs not Attributable to ECAM[92]	B	(776)	(1,136)	(8,347)	(10,483)	(10,999)
Energy Costs Attributable to ECAM	C = A + B	137,769	144,894	140,539	145,001	147,799
Base ECAM Energy Costs Included in Annual Revenue Requirement[93]	D	132,338	139,048	136,320	141,255	147,070
Annual Deferral to ECAM	E = C - D	5,431	5,846	4,219	3,746	729
Annual ECAM Collected thru Rate Adjustments	F	-	4,486	6,528	4,946	3,529
ECAM Account Opening Balance January 1	G	-	5,431	6,791	4,482	3,282
ECAM Closing Balance December 31	**J = E - F + G**	**5,431**	**6,791**	**4,482**	**3,282**	**482**
Total Energy Costs Collected thru Revenue Requirement and ECAM Collection	**K = F + D - B**	**133,114**	**144,670**	**151,195**	**156,684**	**161,598**
Net Energy Costs (Deferred) Collected thru the ECAM Account	**L = K – A**	**(5,431)**	**(1,360)**	**2,309**	**1,200**	**2,800**

A detailed ECAM continuity schedule is provided in Appendix H.

Intergenerational Equity versus Rate Stability

In Order UE19-08, the Commission expressed concerns about applying a rate stability adjustment to the ECAM base rate such that the ECAM base rate is less than the actual energy supply cost.

First, the Commission was concerned that current ratepayers are not paying the full cost of energy consumed by them, causing intergenerational inequity and inappropriate price signals for customers. With respect to intergenerational equity, recovering costs over a three-year period versus a one-year period should not be considered a significant delay. With respect to price signals, stable and predictable rate increases would allow customers time to respond to the increasing cost of electricity and make changes to manage their consumption.

[92] Energy costs not attributable to ECAM from January 1, 2021 to February 28, 2022 includes insurance, property tax and training, net of the amortization of the Point Lepreau Deferral Charge. Effective March 1, 2023 this line includes all costs excluded from ECAM under Order UE21-05. As well, the Provincial Debt Repayment that is proposed to be included in revenue requirement beginning March 1, 2023 is not proposed to flow through ECAM.

[93] Refer to the detailed ECAM continuity schedule provided in Appendix H.

Second, the Commission was concerned about the Company earning a rate of return on the ECAM balance. The Fair Return Standard, discussed in Section 5.2.1 of this Application, is a fundamental regulatory standard that supports the Company's right to earn an approved return on costs incurred by the Company but not yet recovered from customers. This is part of the trade-off between intergenerational equity and rate stability. However, the deferral of energy supply costs within the rate-setting period is a relatively short period by regulatory standards.

5.3.2 Rate of Return Adjustment

The Rate of Return Adjustment Account ("RORA") was first approved in Order UE11-04 to defer, with interest, collections from customers in excess of the approved returns on average common equity for 2011 and 2012. The accumulated amounts were to be returned to customers once the PEI Energy Accord ended. Therefore, on March 1, 2013, the Company began refunding the actual 2011 RORA and forecast 2012 RORA as part of the legislated rates for the period of March 1, 2013 to February 29, 2016.

During the period of March 1, 2013 to February 29, 2016, the Company recorded a RORA amount each year. In accordance with Order UE16-04, the Company refunded the December 31, 2015 RORA balance over the period of March 1, 2016 to February 28, 2019, at the rates approved by the Commission in Appendix A of Order UE16-04.

Also in accordance with Order UE16-04, over collections accumulated during the period from January 1, 2016 to February 28, 2019 were recorded in a separate RORA account to be refunded to customers commencing March 1, 2019, or as further directed by the Commission. The March 1, 2019 RORA refund rate remained in effect until December 31, 2020. In Order UE20-06, the Commission ordered the balances of the Weather Normalization Reserve and ECAM be netted against the RORA balance and approved the existing RORA refund rate of $0.0007 per kWh to customers, effective January 1, 2021.

Table 5-29 provides a summary of the activity in the RORA account during 2021 and the balance as of December 31, 2021.

TABLE 5-29 **RORA Account – 2021 Transactions ($000)**		
RORA Balance - December 31, 2020	A	1,436
Less: Refunded to Customers - January 1 - December 31, 2021	B	(1,080)
Plus: Accrued Interest - January 1 - December 31, 2021	C	21
Pre-2021 RORA Balance	D = A + B + C	377
Plus: 2021 RORA	E	238
RORA Balance - December 31, 2021	**F = D + E**	**615**

In 2021 the Company recognized a RORA of $238,000, as a result of savings in short-term debt interest and general and administration costs, partially offset by higher-than-planned transmission and distribution costs, depreciation and tax expenses.

Table 5-30 provides a summary of the forecast activity in the RORA account from December 31, 2021 to February 28, 2023.

TABLE 5-30 **RORA Account - 2022 Forecast Transactions ($000)**		
RORA Balance - December 31, 2021	A	615
Less: Refunded to Customers - January 1 - December 31, 2022	B	(978)
Plus: Accrued Interest - January 1 - December 31, 2022	C	6
Plus: Forecast 2022 RORA[94]	D	500
Forecast RORA Balance - December 31, 2022	E = A + B + C + D	143
Less: Refunded to Customers - January 1 - February 28, 2023	F	(196)
Forecast RORA Balance - February 28, 2023	**H = E + F**	**(53)**

As Table 5-30 shows, the Company forecasts a minimal balance remaining in the RORA account leading into the next rate-setting period. Throughout 2022 and up to February 28, 2023, the Company will continue to refund RORA at the current approved rate of $0.0007 per kWh, which was approved by the Commission in Order UE20-06. This will result in a small over-refund to customers of approximately $53 thousand.

[94] Maritime Electric currently forecasts an over collection from customers of approximately $500 thousand in 2022, driven by higher residential sales in the first quarter of 2022. This sales increase is associated with unusually high furnace oil prices incenting customer to temporarily use electric heating sources. The US Energy Information Administration's most recent Short Term Energy Outlook has West Texas Intermediate Oil prices returning to more stable pricing in the next six months as the energy market adjusts to recent pressure from the events occurring in Eastern Europe. Therefore, sales in the first quarter of 2022 are not indicative of a longer-term trend.

Given the small RORA balance forecast to be owing from customers at February 28, 2023, the Company is proposing to net this balance with the balance owed to customers for the 2020 Revenue Shortfall as discussed in Section 5.3.3.

5.3.3 2020 Revenue Shortfall

In Order UE20-06, the Commission approved a regulatory deferral of approximately $2.8 million, to recover a shortfall in the Company's actual revenue requirement for 2020, which was collected through approved rates over a fourteen-month period from January 1, 2021 to February 28, 2022.[95]

Order UE20-06 also directed the Company to file an updated calculation of the revenue shortfall based on actual sales up to December 31, 2021. Subsequently, in a letter of direction dated January 22, 2021, the Commission directed the Company to issue bill credits to customers such that the January 1, 2021 rate increase was applied on a pro-rata basis to energy consumed on and after January 1, 2021. Together, these two directions resulted in an additional $282,966 being added to the shortfall deferral in 2021.[96]

As a result of customer basic rates remaining unchanged beyond February 28, 2022, approximately $2.1 million is forecast to be over collected from customers as of February 28, 2023 and will be deferred as a regulatory liability owed to customers.[97] The Company is proposing to net this deferral with the February 2022 RORA balance, as discussed in Section 5.3.2. Therefore, the net balance owing to customers is forecast to be approximately $2.0 million.[98]

The Company is proposing to refund this balance to customers as a rate rider over a 12-month period from March 1, 2023 to February 29, 2024 at a rate of $0.00145 per kWh as calculated in Table 5-31.

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95 Original 2020 Revenue Shortfall amount was calculated as $2,755,214, and collected over a fourteen-month period at $196,801 per month.

96 On August 11, 2021, the Company filed a final reconciliation of bill credits issued to customers and the 2020 revenue shortfall, totalling $3,038,180, which was accepted by the Commission in a communication dated September 10, 2021.

97 Continued monthly amortization of $196,801 for an additional 12 months (i.e., March 2022 to February 2023) totals $2,078,646, or approximately $2.1 million.

98 $2,078,646 minus $53,000 equals $2,025,697, or approximately $2.0 million.

TABLE 5-31 Proposed Revenue Shortfall Refund per kWh to be applied to Customers' Bills Effective March 1, 2023 to February 28, 2024		
Forecast Revenue Shortfall Balance, February 28, 2023 ($)	A	2,025,697
Forecast Sales - March 1, 2022 to February 28, 2023 (kWh)	B	1,396,277,700
Proposed March 1, 2023 Refund ($/kWh)	**C = A/B**	**0.00145**

5.3.4 Weather Normalization Reserve

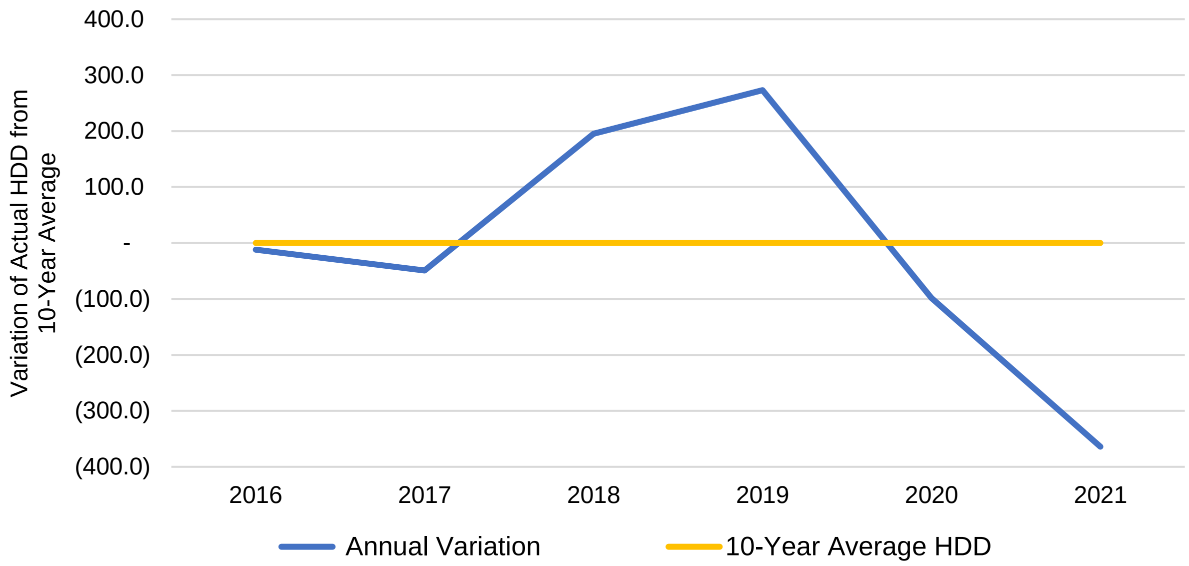
Weather normalization deferrals are part of a broader group of utility deferral reserves designed to mitigate volume or demand fluctuations. The purpose of Maritime Electric's Weather Normalization Reserve ("WNR") is to stabilize electricity rates charged to customers by removing the volatility in sales and energy supply costs caused by temperature changes relative to the 10-year historical averages. In Orders UE16-04 and UE16-04R, the Commission granted interim approval to adopt a Weather Normalization Mechanism and Reserve for the period January 1, 2016 to February 28, 2019, which was extended to February 28, 2022 in Order UE19-08.

The Company is proposing that the interim WNR be approved on a permanent basis for the rate-setting period and future years.

Changing weather patterns are becoming more common with climate change, and the increased variability of weather patterns leads to forecast risk as the weather data is used to develop load and demand projections. In addition, increased penetration of electric space heating over the last 10 years has introduced greater sales volatility from variations in HDD compared to the 10-year average. The WNR provides an opportunity to mitigate sales volatility due to variations in temperature which benefits both the customer and the utility.

Chart 5-1 provides the actual annual variation of HDD from the 10-year average since the mechanism was first approved in 2016.

CHART 5-1
2016 to 2021 Variation of HDDs



Over the six-year period illustrated in Chart 5-1, the lower-than-normal temperatures in 2018 and 2019, shown by the higher-than-average HDD, were followed by higher-than-normal temperatures in 2020 and 2021. This illustrates the variability of HDD.

Effective December 30, 2019, the WNR balance was set to zero.[99] Since then, warmer-than-normal temperatures in December 2020 and throughout 2021 has led to a December 2021 WNR balance receivable from customers of $1.8 million.

The Company is not proposing to recover this balance in the current rate-setting period for two reasons. First, the balance accumulated over a relatively short period of time of thirteen months and given the approved variable for HDD is based on a 10-year average, the Company considers it reasonable to continue deferring the balance and allow time for the balance to correct itself as it is intended to do.[100]

[99] In Order UE20-06, the Commission directed the December 2019 WNR balance owning to customers of $1.1 million be netted against the ECAM account as of December 31, 2020.

[100] Theoretically, over a ten-year period the variations from HDD balances should trend to zero and so too should the WNR balance.

Second, deferring the recovery of the WNR balance provides some rate relief to customers. Recovering the $1.8 million balance in the current rate-setting period would increase annual costs for customers by approximately 0.125 per cent each year, or 0.40 per cent in total over the rate-setting period.

Therefore, the Company proposes that the WNR balance be deferred and that the collection or refund of the balance be considered as part of its next GRA. The Commission will continue to be informed of the WNR balance through the submission of monthly financial statements and annual reporting requirements.

5.3.5 CTGS Reserve Variance

In Order UE20-06, the Commission approved the regulatory deferral for the unrecovered depreciation and reserve variance amortization of the CTGS and, as a result, the CTGS reserve variance of $10.7 million was recognized at the end of 2020.[101]

In assessing an appropriate period over which to recover this regulatory deferral from customers, the Company considered the two regulatory principles, intergenerational equity and rate stability, which were discussed at the beginning of Section 5.3. In addition, the Company considered the recovery period contemplated by the Commission.[102] The Company considered recovery periods of three or five years.

Amortizing the deferral over the current rate-setting period of three years would be more in line with the principal of intergenerational equity but would result in annual amortization of $3.6 million per year.

Alternatively, amortizing the deferral over a five-year period would be more in line with the principal of rate stability and would result in annual amortization of $2.1 million per year. In comparison, an amortization period of five versus three years reduces the increase in annual cost

[101] Order UE20-06 also directed the Company to obtain a technical update to the 2017 Depreciation Study as at December 31, 2019, which indicated that the CTGS accumulation reserve was $10.7 million.

[102] In 2020, during the interrogatory process on the Application for March 1, 2020 and March 1, 2021 Rates, the Commission requested that the Company provide rate impacts of several rate setting scenarios where the CTGS Reserve Variance Deferral was amortized over a five-year period.

for customers by approximately 0.3 per cent for each year, or 0.9 per cent in total over the rate-setting period.

The Company is proposing to amortize the CTGS reserve variance over five years at $2.1 million per year. This extends beyond the current rate-setting period; however, the final decommissioning costs will not be known until the demolition is complete in 2025. In proposing a five-year amortization period, the Company also considered this timeline reasonable given the size of the deferral and giving consideration to other increases in revenue requirement that are placing increasing pressure on rates. The proposed amortization of the CTGS reserve variance is included in Section 5.1.5 of this Application.

5.3.6 Provincial Debt Repayments

In Order UE20-06, the Commission approved the current collection rate of $0.0036 per kWh as a rate rider to recover the debt repayment costs associated with the PEIEC's expected financing arrangements for those deferred energy costs assumed by the Province under the PEI Energy Accord.[103] The Commission also ordered (i) any over collection not to be paid to the Province but instead be held in a separate account to be refunded or remitted as ordered by the Commission and (ii) that the Company include the amount of the debt repayment in its revenue requirement for collection through basic rates or propose an alternative method of collection that will avoid any over or under collection.

With respect to item (i), the Company forecasts an under collection balance of $286 thousand based on actual sales to the end of 2021 and forecast sales for the period January 1, 2022 to February 28, 2023 as shown in Table 5-32.

[103] Under the PEI Energy Accord, the Province of PEI assumed costs associated with exiting the Dalhousie Participation Agreement and certain extraordinary costs associated with a refurbishment of Point Lepreau.

TABLE 5-32 Provincial Debt Repayment Balance[104]				
Collection Period	**Energy Sales (kWh)**	**Collections ($000)**	**Remitted to PEIEC ($000)**	**Balance Under (Over) Collected ($000)**
2021[105]	1,325,999,756	(4,894)	5,182	288
2022	1,396,859,660	(5,028)	5,182	154
2023[105]	343,222,427	(1,236)	1,080	(156)
Total	**3,066,081,843**	**(11,158)**	**11,444**	**286**

Order UE20-06 does not specifically address an under collection situation. However, the Company considers it logical that under collections would be treated similar to the Commission's direction for over collections; the amount should be collected from customers as directed by the Commission. Therefore, the Company proposes the amortization of the under collected balance over the rate-setting period (i.e., 36 months) and collect the amortization in the revenue requirement. The proposed annual amortization is included in Section 5.1.5 of the Application.[106]

As directed by the Commission with respect to item (ii) above, the Company proposes removing the related rate rider and instead has included the expected monthly payments in revenue requirement as shown in Table 5-3 of Section 5.1.1 of this Application, which will avoid over or under collections during the rate-setting period.

5.3.7 Point Lepreau Write-Down

In 2001 the Company recorded a deferred asset of approximately $5.9 million with respect to the $450 million write-down of Point Lepreau recognized by NB Power in 1998, subject to a Unit Participation Agreement (i.e., the Point Lepreau Participation Agreement) between the two companies. Under the provisions of the *Electric Power Act*, effective January 1, 2004, the Company is permitted to recover these deferred costs but under such terms, timelines and

[104] Effective March 1, 2023, the Provincial Debt recovery is included in the revenue requirement, in accordance with Order UE20-06.

[105] The under and over collection balances for 2021 and 2023, respectively, cannot be recalculated in Table 5-33. Energy sales reflect the energy billed in that calendar year, yet the recovery of the debt repayment costs is based on when the energy was consumed. Therefore, the collections in 2021 and forecast collections in 2023 include the prorating of proposed rate changes for energy consumed in the prior month (i.e. December 2020 consumption billed in January 2021 and February 2023 consumption billed in March, 2023).

[106] $286,000 / 36 months x 12 months = $95,000 per year.

conditions as the Commission determines.[107] The Commission has issued two orders permitting the continued amortization of the deferred asset based on Point Lepreau's estimated useful life.

At December 31, 2021, the unamortized balance was approximately $1.3 million and the annual amortization of $93,400, which is included in Section 5.1.5 of this Application, was approved by the Commission in Order UE05-08.

5.4 Government Collections

The Company currently collects two rate riders on behalf of the PEIEC in approved customer rates. The first is for Provincial debt repayment costs. As discussed in Section 5.3.6 above, the Company is proposing to remove the approved rate rider of $0.0036 per kWh and instead include the annual cost for the debt repayment in the revenue requirement. The annual debt repayment costs are included in Section 5.1.1 of this Application.

The second rate rider is the collection of DSM costs on behalf of the PEIEC as per their Energy Efficiency and Conservation ("EE&C") Plan. The current approved rate rider is $0.0013 per kWh, which was approved by the Commission in Order UE20-06, and is based on the forecast funding requirement to be collected from customers under the EE&C Plan for the period of January 1, 2021 to February 28, 2022.

The PEIEC currently has an application before the Commission to approve a three-year plan from 2022/2023 to 2024/2025 ("proposed EE&C Plan"). As filed, the proposed EE&C Plan will require annual contributions from Maritime Electric customers of $869,000 in 2022 and $868,000 in each of 2023 and 2024, after reductions of over-collections realized by the PEIEC under the existing EE&C Plan.

At this time, it is unknown if or when the proposed EE&C Plan will be approved. Given that uncertainty, the Company is proposing that the earliest date by which the collection of a new rate rider amount be made effective be March 1, 2023, to coincide with the Company's proposed effective date of its customer rate change.

[107] The recovery of Maritime Electric's portion of the Point Lepreau write-down is provided for in Section 47(4)(a)(ii) of the *Electric Power Act*.

The following analysis assumes that the proposed EE&C Plan will ultimately be approved as filed with respect to the required collection amounts from Maritime Electric customers. The continuation of the existing rate rider amount until March 1, 2023 will result in an over collection for the period March 1, 2022 to February 28, 2023 as shown in Table 5-33.

TABLE 5-33 Proposed EE&C Plan Collections March 1, 2022 to February 29, 2023		
Forecast Sales - March 1, 2022 to February 28, 2023 (kWh)	A	1,395,847,900
Approved Rate Rider ($/kWh)	B	0.0013
Forecast Collections - March 1, 2022 to February 28, 2023 ($000)	**C = A x B**	**1,815**
Proposed Funding Required for PEIEC EE&C Plan ($000)	D	(869)
Forecast Over Collection, March 1, 2022 to February 28, 2023 ($000)	**E = C - D**	**946**

The Company is proposing that the forecast over collection be used to reduce the collection rate to nil for the period March 1, 2023 to February 29, 2024.[108] The remaining over-collection balance of $78,000 would then be used to reduce the amount to be recovered from March 1, 2024 to February 28, 2026 to $790,000.[109]

The proposed EE&C Plan does not extend to the final year of Maritime Electric's rate-setting period but it is reasonable to assume that DSM programs will be extended as electrification of home heating and transportation continues. Therefore, the Company is proposing that the estimated gross funding requirement for 2024/2025 under the proposed EE&C Plan of $1,732,000 be used to estimate the requirement for the period March 1, 2025 to February 28, 2026.[110]

Table 5-34 summarizes the Company's proposal of funding requirements to be collected from customers and the proposed collection rate over the rate-setting period.

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108 Proposed EE&C Plan collection for March 2023 to February 2024 is $868,000.

109 Total over collection of $946,000 less $868,000 equals $78,000. The proposed EE&C Plan collection for March 2024 to February 2024 of $868,000 would be reduced by $78,000 to $790,000.

110 The estimate gross funding requirement of $1.7 million is based on the proposed EE&C Plan contribution amount before the over-collection from the previous EE&C Plan was applied.

TABLE 5-34 Proposed EE&C Plan Collection Requirements and Rate Rider March 1 to February 28			
	2023/24	**2024/25**	**2025/26**
Forecast Collection Requirement ($000)	-	790	1,732
Forecast Sales (kWh)	1,396,277,700	1,416,675,800	1,436,087,300
Collection rate ($/kWh)	-	0.00056	0.00121

In the proposed EE&C Plan, the PEIEC has suggested that the Company remit a fixed monthly amount to the PEIEC with any over or under collections due to sales fluctuations to be held in a regulatory deferral account to be managed by the utility. Should the Commission approve this change, the Company is proposing that such a change become effective March 1, 2023 and reflect a true-up of the balance of any additional over and under collections.

6.0 RATE BASE AND REVENUE REQUIREMENT

6.1 Overview

This section of evidence summarizes the Company's forecast 2023 to 2025 average rate base and revenue requirements based on the proposals presented in this Application.

Table 6-1 summarizes the forecast average rate base and revenue requirement for the rate-setting period.

TABLE 6-1
Rate Base and Revenue Requirement ($000, except %)

	2023 Forecast	2024 Forecast	2025 Forecast
Average Rate Base	471,023	492,256	519,376
Revenue Requirement	249,256	261,902	273,869
Return on Rate Base	6.9%	6.9%	6.9%

To generate the revenue necessary to meet the Company's forecast revenue requirements in 2023 to 2025, average increases in existing customer rates of approximately 3.0 per cent on each of March 1, 2023, 2024 and 2025 will be required.

6.2 Rate Base

Rate base is the total of the investor-funded plant, facilities and other investments used by the Company to provide service to customers. Over the rate-setting period, annual rate base is forecast to increase by an average of $26 million per year.[111] This rate base increase is comprised of an average increase in fixed assets of $41 million annually and an average decrease in the other rate base components of $15 million annually.[112]

Table 6-2 details the various components of rate base for 2022 to 2025.

[111] Annual rate base increase based on figures from Table 6-2 in thousands: $536,382 - $458,218 / 3 = $26,055.
[112] Annual fixed asset increase based on figures from Table 6-2 in thousands: $608,664 - $485,612 / 3 = $41,017.

TABLE 6-2
Annual and Average Rate Base ($000, except %)

	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Fixed Assets	485,612	518,341	556,280	608,664
Additions to Rate Base:				
CTGS Reserve Variance	10,672	8,538	6,403	4,269
ECAM	6,791	4,482	3,282	482
Intangible Assets	4,150	4,300	4,450	4,600
Other Post-Employment Benefits	1,759	1,622	1,484	1,347
Weather Normalization Reserve	1,789	1,789	1,789	1,789
Deferred Charges	1,212	1,325	1,137	948
Deferred Financing	1,213	1,191	1,567	1,837
Subtotal of Additions to Rate Base	**27,586**	**23,247**	**20,112**	**15,272**
Deductions from Rate Base:[113]				
Future Income Tax	(30,120)	(35,826)	(42,055)	(48,828)
Contributions	(25,484)	(26,091)	(34,578)	(41,352)
Employee Future Benefits	(7,064)	(7,224)	(7,382)	(7,541)
RORA Refund	(143)	-	-	-
Subtotal of Deductions from Rate Base	**(62,811)**	**(69,141)**	**(84,015)**	**(97,721)**
Working Capital:				
Inventory	3,000	3,000	3,000	3,000
Operating Expenses[114] x 3.6%	6,426	6,605	6,903	7,077
Income Taxes Paid x 3.6%	90	90	90	90
Subtotal of Working Capital	**9,516**	**9,695**	**9,993**	**10,167**
Annual Rate Base	**459,903**	**482,142**	**502,370**	**536,382**
Average Rate Base		**471,023**	**492,256**	**519,376**
Year over Year Variance[115]		*5.5%*	*4.5%*	*5.6%*

6.2.1 Fixed Assets

As indicated, the continued investment in the electrical system is driving the increase in rate base over the rate-setting period. Table 6-3 provides a reconciliation of the fixed asset increase.

113 As per Commission Order UE20-06, the balance of the 2020 revenue shortfall deferral is not included in forecast rate base.
114 Excludes non-regulated expenses.
115 2023 forecast variance over 2022 forecast based on a 2022 forecast average rate base of $446,586,000.

TABLE 6-3 Fixed Assets ($000)				
	2022 Forecast	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
Opening balance	455,744	485,612	518,341	556,280
Additions[116]	47,592	50,404	64,356	81,107
Depreciation expense	(25,663)	(28,429)	(30,225)	(32,468)
Retirement expense	7,939	10,754	3,808	3,745
Ending balance	**485,612**	**518,341**	**556,280**	**608,664**

6.2.2 Additions to Rate Base

CTGS Reserve Variance

As per Order UE20-06, the Commission approved a regulatory deferral account for the CTGS unrecovered depreciation and reserve variance amortization (i.e., accumulated reserve variance) associated with the two-year gap in implementing the 2017 Depreciation Study and changes to the retirement year assumption. The 2017 Depreciation Study estimated the accumulated reserve variance to be $9,654,524.

Also per Order UE20-06, the Commission directed the Company to obtain a technical update to the 2017 Depreciation Study as at December 31, 2019. This technical update resulted in an increase to the CTGS accumulation reserve variance to $10,672,000 related to unit #8 being retired in 2020.

Reflecting the recognition of the regulatory deferral of $10,672,000, the 2020 Depreciation Study indicates a minor increase of only $113,307 to the CTGS accumulated reserve variance. This minor increase will ultimately become part of the final true-up to actual costs incurred to decommission and demolish the CTGS.

As indicated in Section 5.3.5, the Company proposed that the CTGS accumulated reserve variance be collected from customers over a five-year period beginning in March 2023.

[116] Additions are net of forecast construction work-in-progress for capital additions not in service at year end.

ECAM

The ECAM balance is discussed in detail in Section 5.3.1 of this Application. As the declining balance demonstrates, the Company proposes to collect substantially all of the ECAM balance over the rate-setting period.

Intangible Assets

Intangible assets are comprised of internally developed software and costs associated with the purchase of transmission and distribution land rights, and are amortized in accordance with the rates proposed in the 2020 Depreciation Study.

Other Post-Employment Benefits

The other post-employment benefits balance, in accordance with Order UE14-02, is the unamortized balance of the deferral of net actuarial gains and losses as determined by actuarial valuations.

Weather Normalization Reserve

The Weather Normalization Reserve is forecast to have a stable balance over the rate-setting period, as discussed in Section 5.3.4 in this Application.

Deferred Charges

The deferred charges balance related to: (i) the Point Lepreau write-down, which was discussed in Section 5.3.7 of this Application; and, from 2023, (ii) the Provincial debt repayment, which was discussed in Section 5.3.6.

Deferred Financing

The deferred financing balance is the accumulation of costs associated with the issuance of first mortgage bonds, which are amortized over the term of the applicable bond. The forecast balance over the rate-setting period reflects the continued amortization of actual costs incurred up to December 31, 2021 and the amortization of forecast costs associated with the planned issuance of $40 million and $30 million first mortgage bonds in 2024 and 2025, respectively.

6.2.3 Deductions from Rate Base

Future Income Tax

The future income tax liability is the required recognition of temporary differences between the tax and accounting basis of assets and liabilities.[117] The increase of the liability over the rate-setting period is due to the continued investment in the electrical system.

Contributions

As shown in Table 6-4, the contribution balance reflects the cost of fixed asset additions contributed by customers, net of depreciation over the estimated service life of the related assets. The increase in the liability over the rate-setting period reflects the Company's estimate of the required contributions associated with planned fixed asset additions.

TABLE 6-4
Contributions ($000)

	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Opening balance	(23,493)	(25,484)	(26,091)	(34,578)
Additions	(3,538)	(2,250)	(10,250)	(8,750)
Depreciation expense	1,547	1,643	1,763	1,976
Ending balance	**(25,484)**	**(26,091)**	**(34,578)**	**(41,352)**

Employee Future Benefits

The employee future benefit liability represents the Company's obligation associated with its post-employment benefit plan, which provides extended health benefits to employees during retirement. The increase in the liability over the rate-setting period reflects the Company's forecast of annual increases of $250,000 or 3 per cent.

RORA Refund

This category includes the balances related to the RORA, which is discussed in Section 5.3.2.

[117] The temporary differences are primarily associated with the difference between the capital cost allowance for tax purposes and depreciation expense for accounting purposes.

6.2.4 Working Capital

A consistent year-end inventory level, comparable to historical actuals, has been assumed for the rate-setting period.

The operating expense and income taxes paid percentage of 3.6 per cent is in accordance with previous rate applications.

6.3 Revenue Requirement

6.3.1 Summary of Revenue Requirements

The Company's revenue requirement to be recovered from basic rates is forecast to average approximately $245 million per year during the rate-setting period.

Table 6-5 summarizes the components of the revenue requirement for 2023 to 2025 based on the proposals presented in this Application.

TABLE 6-5
Revenue Requirement ($000, except %)

	Reference	2023 Forecast	2024 Forecast	2025 Forecast
Energy Supply Costs	Section 5.1.1, Table 5-3	148,886	155,484	158,798
ECAM Deferral Adjustment	Section 5.3.1, Table 5-29	(4,219)	(3,746)	(729)
Transmission and Distribution	Section 5.1.2, Table 5-5	21,394	22,699	23,815
General and Administrative	Section 5.1.3, Table 5-10	13,185	13,559	13,972
Depreciation	Section 5.1.5, Table 5-12	29,094	30,785	32,816
Finance Charges	Section 5.1.6, Table 5-14	13,797	14,277	14,593
Income Taxes	Section 5.1.7, Table 5-16	8,459	8,994	9,538
Return	Section 5.1.8, Table 5-17	18,660	19,850	21,066
Total Revenue Requirement		**249,256**	**261,902**	**273,869**
Other Revenue	Section 5.1.4, Table 5-11	(16,188)	(16,546)	(16,877)
Revenue Requirement from Basic Rates		**233,068**	**245,356**	**256,992**
Year Over Year Variance[118]		*4.6%*	*5.3%*	*4.7%*

Table 6-6 presents the revenue requirement by customer class.

[118] 2023 increase over 2022 based on forecast 2022 revenue requirement from basic rates of $222,717,000.

TABLE 6-6 Revenue Requirement by Customer Class ($000)			
	2023 Forecast	**2024 Forecast**	**2025 Forecast**
Residential	130,251	138,666	147,044
General Service	69,702	72,018	74,172
Large Industrial	16,046	17,018	17,557
Small Industrial	14,498	14,942	15,371
Street Lighting	2,096	2,212	2,324
Unmetered	475	500	524
Total Revenue Requirement from Basic Rates	**233,068**	**245,356**	**256,992**
Other Revenue	16,188	16,546	16,877
Total Revenue Requirement	**249,256**	**261,902**	**273,869**

6.3.2 Return on Average Rate Base

Return on rate base is the total annual cost of financing rate base including the cost of short-term debt, long-term debt and shareholder's equity. It is, thereby, equivalent to the Company's total weighted average cost of capital for the year.

Table 6-7 provides the calculation of rate base earnings and return on average rate base for 2023 to 2025.

TABLE 6-7 Return on Average Rate Base ($000, except %)				
	Reference	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
Total Revenue Requirement	Section 6.3.1, Table 6-6	249,256	261,902	273,869
Energy Supply Costs	Section 5.1.1, Table 5-3	(148,886)	(155,484)	(158,798)
ECAM Deferral Adjustment	Section 5.3.1, Table 5-29	4,219	3,746	729
Transmission and Distribution	Section 5.1.2, Table 5-5	(21,394)	(22,699)	(23,815)
General and Administrative	Section 5.1.3, Table 5-10	(13,185)	(13,559)	(13,972)
Depreciation	Section 5.1.5, Table 5-12	(29,094)	(30,785)	(32,816)
Amortization of Financing Costs	Section 5.1.6, Table 5-14,	(22)	(24)	(31)
Income Taxes	Section 5.1.7, Table 5-16	(8,459)	(8,994)	(9,538)
Total Earnings on Rate Base		**32,435**	**34,103**	**35,628**
Average Rate Base	Section 6-2, Table 6-2	471,023	492,256	519,376
Return on Average Rate Base		**6.9%**	**6.9%**	**6.9%**

As shown in Table 6-6, annual rate base earnings are forecast to increase by an average of $1.9 million per year during the rate-setting period,[119] and the annual return on average rate base is forecast to be 6.9 per cent for each year.

The return on average rate base of 6.9 per cent each year of the rate-setting period reflects the proposed increase in ROE from 9.35 per cent to 9.95 per cent, which is partially offset by a lower average cost of debt as recent and forecast debt issuances are forecast at lower interest rates than previous debt issuances.

6.4 Financial Forecast Results

The financial forecast uses the inputs as outlined in this evidence. A summary of the Company's actual results for 2021 and its financial forecast for the period 2022 to 2025 is provided in Appendix I.

[119] Average of $1.9 million based on forecast 2022 rate base earnings of $29,860,000: ($35,628,000 – $29,860,000) / 3 years = $1,923,000 average increase per year.

7.0 CUSTOMER RATES

7.1 Overview

This section of evidence summarizes the Company forecast 2023 to 2025 proposed rates and the impact of the proposed rate changes on customers' annual costs.

7.2 Proposed Rates

This Application requests Commission approval of changes to the energy charge component of customers' rates.[120] The energy charge is comprised of two elements, the basic energy charge per kWh and the rate rider. This Application does not request any changes to the monthly service or demand charges.

The basic energy charge per kWh is designed to recover the Company's revenue requirement set out in Section 6.3 of this Application. Table 7-1 summarizes the proposed basic energy charges per kWh for the four principal classes of customers served by Maritime Electric.

TABLE 7-1
Basic Energy Charge ($/kWh, except %)
Effective March 1

Rate Class	Approved 2022	Proposed			Cumulative Variance over 2022 Rates	Average Annual Variance
		2023	2024	2025		
Residential - First Block	0.1450	0.1558	0.1615	0.1680	15.9%	5.3%
Residential - Second Block	0.1146	0.1231	0.1276	0.1327	15.8%	5.3%
General Service - First Block	0.1789	0.1922	0.1993	0.2072	15.8%	5.3%
General Service - Second Block	0.1159	0.1245	0.1291	0.1342	15.8%	5.3%
Small Industrial - First Block	0.1752	0.1882	0.1951	0.2029	15.8%	5.3%
Small Industrial - Second Block	0.0868	0.0933	0.0967	0.1005	15.8%	5.3%
Large Industrial	0.0698	0.0774	0.0800	0.0832	19.2%	6.4%

The rate riders are collections from or refunds to customers related to amounts owed to or refunded from Maritime Electric or a third-party. This element of the customer energy charge is

[120] The Company is not requesting changes to the currently approved monthly service or demand charges.

not driven by the Company's revenue requirement. Rate riders are set to collect the same per kWh charge from all classes of customers. Table 7-2 provides a summary of proposed rate riders.

TABLE 7-2
Rate Riders ($/kWh, except %)
Effective March 1

			Proposed			
	Reference	**Approved 2022**	**2023**	**2024**	**2025**	**Cumulative Change over 2022 Rates**
ECAM Rate Adjustment	Section 5.3.1 Table 5-30	0.00402	0.00486	0.00316	0.00229	(43.0)%
RORA and 2020 Revenue Deferral	Sections 5.3.2 and 5.3.3	(0.00070)	(0.00145)	-	-	n/a
Provincial Debt Recovery[121]	Section 5.4	0.00360	-	-	-	n/a
Energy Efficiency Program	Section 5.4 Table 5-36	0.00130	-	0.00056	0.00121	(6.9)%
Energy Charge for Rate Riders		**0.00822**	**0.00341**	**0.00372**	**0.00350**	**(57.4)%**

Table 7-3 provides the total energy charge per kWh for the four principal classes of customers served by Maritime Electric, which is the sum of the total energy charge for the rate riders, from Table 7-2, and the basic energy charge for each customer class, from Table 7-1.

TABLE 7-3
Total Energy Charge ($/kWh, except %)
Effective March 1

		Proposed				
Rate Class	**Approved 2022**	**2023**	**2024**	**2025**	**Cumulative Variance over 2022 Rates**	**Average Annual Variance**
Residential - First Block	0.1532	0.1592	0.1652	0.1715	11.9%	4.0%
Residential - Second Block	0.1228	0.1265	0.1313	0.1362	10.9%	3.6%
General Service - First Block	0.1871	0.1956	0.2030	0.2107	12.6%	4.2%
General Service - Second Block	0.1241	0.1279	0.1328	0.1377	10.9%	3.6%
Small Industrial - First Block	0.1834	0.1916	0.1988	0.2064	12.5%	4.2%
Small Industrial - Second Block	0.0950	0.0967	0.1004	0.1040	9.5%	3.2%
Large Industrial	0.0780	0.0808	0.0837	0.0867	11.1%	3.7%

[121] As per Section 5.4, the amounts owing to the Province of PEI for assumed costs associated with exiting the Dalhousie Participation Agreement and certain extraordinary costs associated with the refurbishment of Point Lepreau are included in revenue requirement beginning on March 1, 2023, as per Commission Order UE20-06, which changes the recovery from customers from a rate rider in 2022, as presented in Table 7-2, to basic rates beginning in 2023, as presented in Table 7-1.

Appendix A provides a comprehensive schedule of existing customer rates, by customer class, effective March 1, 2022 and the proposed customer rates for March 1, 2023, March 1, 2024 and March 1, 2025 based on this Application.

7.3 Customer Impact of Proposed Rates

The rate increase experienced by customers, as proposed in this Application, will vary depending on the customer's energy consumption and demand, if applicable. The following discussion seeks to provide the rate impact for a selected benchmark energy consumption and demand, if applicable.

Table 7-4 illustrates the estimated annual cost, by component, for a rural residential customer using a benchmark consumption of 650 kWh per month, or 7,800 kWh per year.

TABLE 7-4
Annual Cost for a Benchmark Rural Residential Customer
March 1 to February 28

	Approved	Proposed		
	2022/2023	**2023/2024**	**2024/2025**	**2025/2026**
Service Charge	$ 323.04	$ 323.04	$ 323.04	$ 323.04
Basic Energy Charge	1,131.00	1,211.67	1,257.82	1,308.26
ECAM Charge	30.05	37.64	25.20	18.14
Provincial Debt Recovery	27.97	1.17	-	-
Provincial Energy Efficiency Program	10.52	0.44	4.19	9.23
RORA Refund and Revenue Shortfall	(5.71)	(11.08)	(0.47)	-
Subtotal	**$ 1,516.87**	**$ 1,562.88**	**$ 1,609.78**	**$ 1,658.67**
HST	227.53	234.43	241.47	248.80
Provincial Clean Energy Rebate	(119.38)	(123.98)	(128.67)	(133.56)
Total Annual Cost	**1,625.02**	**1,673.33**	**1,722.58**	**1,773.91**
Annual Increase				
Before Tax	**2.0%**[122]	**3.0%**	**3.0%**	**3.0%**
After Tax	**2.0%**	**3.0%**	**2.9%**	**3.0%**

Table 7-5 illustrates the estimated annual cost, by component, for an urban residential customer using a benchmark consumption of 650 kWh per month, or 7,800 kWh per year.

[122] Rate increase approved per Order UE22-01.

TABLE 7-5 Annual Cost for Benchmark Urban Residential Customer March 1 to February 28				
	Approved	**Proposed**		
	2022/2023	**2023/2024**	**2024/2025**	**2025/2026**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	1,131.00	1,211.67	1,257.82	1,308.26
ECAM Charge	30.05	37.64	25.20	18.14
Provincial Debt Recovery	27.97	$1.17	-	-
Provincial Energy Efficiency Program	10.52	0.44	4.19	9.23
RORA Refund and Revenue Shortfall	(5.71)	(11.08)	(0.47)	-
Subtotal	**1,488.67**	**1,534.68**	**1,581.58**	**1,630.47**
HST	223.30	230.20	237.24	244.57
Provincial Clean Energy Rebate	(119.38)	(123.98)	(128.67)	(133.56)
Total Annual Cost	**$ 1,592.59**	**$ 1,640.90**	**$ 1,690.15**	**$ 1,741.48**
Annual Increase:				
Before Tax	**2.1%**[123]	**3.1%**	**3.1%**	**3.1%**
After Tax	**2.0%**	**3.1%**	**3.0%**	**3.0%**

Table 7-6 illustrates the estimated annual cost, by component, for a general service customer using a benchmark consumption of 10,000 kWh per month, or 600,000 kWh per year, and demand of 50 KW per month, or 600 KW per year.

[123] Rate increase approved per Order UE22-01.

TABLE 7-6 Annual Cost for Benchmark General Service Customer March 1 to February 28				
	Approved	**Proposed**		
	2022/2023	**2023/2024**	**2024/2025**	**2025/2026**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Demand Charge	4,834.80	4,834.80	4,834.80	4,834.80
Basic Energy Charge	17,688.00	18,946.00	19,674.50	20,451.00
ECAM Charge	462.30	579.00	387.70	279.15
Provincial Debt Recovery	430.32	17.93	-	-
Provincial Energy Efficiency Program	161.88	6.75	64.40	141.95
RORA Refund and Revenue Shortfall	(87.84)	(170.41)	(7.25)	-
Sub-total	23,784.30	24,508.91	25,248.99	26,001.74
HST	3,567.65	3,676.34	3,787.35	3,900.26
Total Annual Cost	**$ 27,351.95**	**$ 28,185.25**	**$ 29,036.34**	**$ 29,902.00**
Annual Increase:				
Before Tax	**2.0%**[124]	**3.0%**	**3.0%**	**3.0%**
After Tax	**2.0%**	**3.0%**	**3.0%**	**3.0%**

Customers in the small industrial and large industrial rate classes will experience annual increases in electricity costs of approximately 3.0 per cent per year. The annual impact on a per customer basis will, however, be dependent on the level of consumption and demand of that customer.

[124] Rate increase approved per Order UE22-01.

8.0 PROPOSED ORDER

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Sections 10, 13(1) and 20 of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the years March 1, 2023 to February 28, 2026 and for certain approvals incidental to such an order.

UPON receiving an Application by Maritime Electric Company, Limited (the "Company") for approval of proposed amendments to its rates, tolls and charges and certain approvals incidental to such an order;

AND UPON considering the Application as well as the Evidence of the Company;

NOW THEREFORE for the reasons given in the annexed Reasons for Order;

IT IS ORDERED THAT

1. The Schedule of Rates shall be adjusted to reflect the proposals contained in the Application effective March 1, 2023, March 1, 2024 and March 1, 2025 as proposed in Appendix A.

2. The Company's General Rules and Regulations shall be amended to incorporate the terms of this Order and filed with the Commission within 30 days.

3. The base rate per kilowatt hour ("kWh") used in the Energy Cost Adjustment Mechanism ("ECAM") formula approved by the Commission in Order UE21-03 shall be set as follows:

Effective	Rate per kWh
March 1, 2023	$0.09060
March 1, 2024	$0.09370
March 1, 2025	$0.09612

4. The rate adjustment per kWh used in the ECAM formula approved by the Commission in Order UE22-01 shall be set as follows:

Effective	Rate per kWh
March 1, 2023	$0.00486
March 1, 2024	$0.00316
March 1, 2025	$0.00229

5. The interim Weather Normalization Mechanism and Reserve account approved by Order UE19-08 is approved for 2023 and future years.

6. The balance in the Weather Normalization Mechanism and Reserve account be deferred until the next General Rate Application or until the balance exceeds $5 million.

7. Any balance remaining in the Rate of Return Adjustment Account at February 28, 2023 shall be netted with the balance owing to customers for the 2020 Revenue Shortfall.

8. The Company shall refund the balance owing to customers for the 2020 Revenue Shortfall as a rate rider, which will be set at $0.00145/kWh, from March 1, 2023 to February 28, 2024.

9. The Company shall adopt the Depreciation rates recommended in Part VI – Table 1 of the 2020 Depreciation Study filed under Commission Docket UE21605 and as summarized in Appendix D, with the exception of the rates pertaining to the Charlottetown Steam Plant, effective as of January 1, 2023.

10. The Charlottetown Thermal Generating Station ("CTGS") Reserve Variance deferral shall be amortized as part of the Company's annual revenue requirement from January 1, 2023 to December 31, 2027, subject to any revisions that may be approved by the Commission as a result of future depreciation studies, changes to the CTGS decommissioning costs or other reasons approved by the Commission.

11. On or before June 30, 2024, the Company shall file with the Commission an updated depreciation study based on financial results to December 31, 2023.

12. The Company's requested return on average common equity of 9.95 per cent on an average common equity of 40 per cent for 2023, 2024 and 2025 is approved.

13. Costs recoverable from customers on behalf of the Province of Prince Edward Island ("PEI") related to debt repayment costs shall no longer be collected via a rate rider and shall instead be included the Company's revenue requirement to be collected from March 1, 2023 to February 28, 2026.

14. With respect to the Provincial debt repayment costs, annual repayments shall be included in the Company's revenue requirement to be collected in basic rates from March 1, 2023 to February 28, 2026 and no longer collected as a rate rider.

15. Customers shall recover the costs under the Province of PEI's Electricity Efficiency and Conservation Plan (Commission Docket UE41400) on a per kWh basis at the following rates:

Effective	Rate per kWh
March 1, 2023	nil
March 1, 2024	$0.00056
March 1, 2025	$0.00125

DATED at Charlottetown this ____ day of ____, 2022

BY THE COMMISSION:

____
Chair

____
Commissioner

____
Commissioner

APPENDIX A

Section N-28

Schedule of Proposed Rates

March 1, 2023 to February 28, 2026

Maritime Electric Company, Limited

Schedule of Rates

Rate Code		March 1, 2022	March 1, 2023	March 1, 2024	March 1, 2025
110	**Residential**				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1592	$ 0.1652	$ 0.1715
	Energy Charge per kWh for balance kWh	$ 0.1228	$ 0.1265	$ 0.1313	$ 0.1362
131	**Residential Seasonal**				
	Service Charge	$ 26.92	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1592	$ 0.1652	$ 0.1715
	Energy Charge per kWh for balance of kWh	$ 0.1228	$ 0.1265	$ 0.1313	$ 0.1362
133	**Residential Seasonal Option**				
	Service Charge	$ 37.50	$ 37.50	$ 37.50	$ 37.50
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1592	$ 0.1652	$ 0.1715
	Energy Charge per kWh for balance of kWh	$ 0.1228	$ 0.1265	$ 0.1313	$ 0.1362
232	**General Service**				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1871	$ 0.1956	$ 0.2030	$ 0.2107
	Energy Charge per kWh for balance of kWh	$ 0.1241	$ 0.1279	$ 0.1328	$ 0.1377
233	**General Service - Seasonal Operators Option**				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1871	$ 0.1956	$ 0.2030	$ 0.2107
	Energy Charge per kWh for balance of kWh	$ 0.1241	$ 0.1279	$ 0.1328	$ 0.1377
320	**Small Industrial**				
	Demand Charge - per kW	$ 7.46	$ 7.46	$ 7.46	$ 7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$ 0.1834	$ 0.1916	$ 0.1988	$ 0.2064
	Energy Charge per kWh for balance of kWh	$ 0.0950	$ 0.0967	$ 0.1004	$ 0.1040
310	**Large Industrial**				
	Demand Charge per kW	$ 14.50	$ 14.50	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0780	$ 0.0808	$ 0.0837	$ 0.0867
340	**Long Term Contract** (Currently no customers in this rate category)				
	Demand Charge per kW	$ 15.51	$ 15.51	$ 15.51	$ 15.51
	Energy Charge per kWh	$ 0.1044	$ 0.1067	$ 0.1108	$ 0.1149
330	**Short Term Contract** (Currently no customers in this rate category)				
	Demand Charge - per kW	$ 16.79	$ 16.79	$ 16.79	$ 16.79
	Energy Charge per kWh for all kWh in the first block	$ 0.1036	$ 0.1057	$ 0.1098	$ 0.1138
	Energy Charge per kWh for balance of kWh in the month	$ 0.0869	$ 0.0878	$ 0.0912	$ 0.0945

Maritime Electric Company, Limited
Schedule of Rates

	Residential	Type		Annual kWh	Monthly kWh	March 1, 2022	March 1, 2023	March 1, 2024	March 1, 2025
	619	LED	70 W HPS Equivalent St Lights - Rented		15	$ 12.49	$ 12.88	$ 13.28	$ 13.69
	625	LED	100 W HPS Equivalent St Lights - Rented		17	$ 12.93	$ 13.33	$ 13.74	$ 14.17
*	630	HPS	St Lights - Rented	389	32	$ 16.57	$ 17.08	$ 17.61	$ 18.16
*	631	HPS	St Lights - Rented	553	46	$ 21.06	$ 21.72	$ 22.39	$ 23.08
*	632	HPS	St Lights - Rented	799	66	$ 30.12	$ 31.05	$ 32.01	$ 33.00
	633	HPS	St Lights - Rented	1283	106	$ 41.02	$ 42.29	$ 43.60	$ 44.95
	634	HPS	St Lights - Rented	1886	157	$ 48.10	$ 49.59	$ 51.13	$ 52.72
*	635	MV	St Lights - Rented	656	54	$ 16.50	$ 17.01	$ 17.54	$ 18.08
	639	Lanterns	City Lanterns - Rented	389	32	$ 60.56	$ 62.44	$ 64.38	$ 66.38
*	640	HPS	St Lights - Owned	389	32	$ 6.59	$ 6.79	$ 7.00	$ 7.22
*	641	HPS	St Lights - Owned	553	46	$ 8.70	$ 8.97	$ 9.25	$ 9.54
*	642	HPS	St Lights - Owned	779	65	$ 11.70	$ 12.06	$ 12.43	$ 12.82
	643	HPS	St Lights - Owned	1283	107	$ 18.56	$ 19.14	$ 19.73	$ 20.34
	644	HPS	St Lights - Owned	1886	157	$ 29.22	$ 30.13	$ 31.06	$ 32.02
	666	LED	175 W MV Equivalent St Lights - Rented		25	$ 14.41	$ 14.86	$ 15.32	$ 15.79
	670	LED	St Lights - Rented	410	34	$ 16.78	$ 17.30	$ 17.84	$ 18.39
	675	LED	150 W/200 W HPS Equivalent St Lights - Rented		37	$ 15.61	$ 16.09	$ 16.59	$ 17.10
	719	LED	St Lights - Owned	176	15	$ 2.69	$ 2.77	$ 2.86	$ 2.95
*	730	HPS	Yard Lights - Rented	389	32	$ 16.57	$ 17.08	$ 17.61	$ 18.16
*	731	HPS	Yard Lights - Rented	553	46	$ 21.06	$ 21.72	$ 22.39	$ 23.08
*	732	HPS	Yard Lights - Rented	799	66	$ 30.12	$ 31.05	$ 32.01	$ 33.00
	733	HPS	Yard Lights - Rented	1283	106	$ 41.02	$ 42.29	$ 43.60	$ 44.95
	734	HPS	Yard Lights - Rented	1886	157	$ 48.10	$ 49.59	$ 51.13	$ 52.72
*	735	MV	Yard Lights - Rented	656	54	$ 16.50	$ 17.01	$ 17.54	$ 18.08
*	736	MV	Yard Lights - Rented	881	73	$ 20.98	$ 21.63	$ 22.30	$ 22.99
*	737	MV	Yard Lights - Rented	1210	100	$ 29.19	$ 30.10	$ 31.03	$ 31.99
*	740	HPS	Yard Lights - Owned	389	32	$ 6.59	$ 6.79	$ 7.00	$ 7.22
*	741	HPS	Yard Lights - Owned	553	46	$ 8.70	$ 8.97	$ 9.25	$ 9.54
	742	HPS	Yard Lights - Owned	779	65	$ 11.70	$ 12.06	$ 12.43	$ 12.82
	743	HPS	Yard Lights - Owned	1283	107	$ 18.56	$ 19.14	$ 19.73	$ 20.34
	744	HPS	Yard Lights - Owned	1886	157	$ 29.22	$ 30.13	$ 31.06	$ 32.02
	749	LPS	Yard Lights - Owned	869	72	$ 13.63	$ 14.05	$ 14.49	$ 14.94
	753	Flood	Yard Lights - Rented	1283	107	$ 39.16	$ 40.37	$ 41.62	$ 42.91
	754	Flood	Yard Lights - Rented	1886	157	$ 48.84	$ 50.36	$ 51.92	$ 53.53
	755	Halide	Yard Lights - Rented	1148	95	$ 41.17	$ 42.45	$ 43.77	$ 45.13
	756	Halide	Yard Lights - Rented	1878	156	$ 50.83	$ 52.40	$ 54.02	$ 55.69
	757	Halide	Yard Lights - Rented	4346	362	$ 87.62	$ 90.33	$ 93.13	$ 96.02
	759	Halide	St Lights - Owned	533	44	$ 8.14	$ 8.39	$ 8.65	$ 8.92
	760	Halide	St Lights - Owned	894	74	$ 13.67	$ 14.09	$ 14.53	$ 14.98
	761	Halide	St Lights - Owned	1148	95	$ 17.53	$ 18.08	$ 18.64	$ 19.22
	762	Halide	St Lights - Owned	1878	156	$ 28.67	$ 29.56	$ 30.48	$ 31.42
	764	LED	St Lights - Owned	410	34	$ 6.26	$ 6.45	$ 6.65	$ 6.86
	765	Halide	St Lights - Owned	759	63	$ 11.58	$ 11.94	$ 12.31	$ 12.69
	766	LED	St Lights - Owned	295	25	$ 4.50	$ 4.64	$ 4.78	$ 4.93
	775	LED	St Lights - Owned	438	37	$ 6.69	$ 6.89	$ 7.10	$ 7.32
	780	LED	St Lights - Owned	586	49	$ 8.95	$ 9.22	$ 9.51	$ 9.80
	785	LED	St Lights - Owned	718	60	$ 10.94	$ 11.28	$ 11.63	$ 11.99

* These charges are applicable to existing fixtures only.

Maritime Electric Company, Limited
Schedule of Rates

		March 1, 2022	March 1, 2023	March 1, 2024	March 1, 2025
610	Pole Rental -Wood	$ 4.38	$ 4.38	$ 4.38	$ 4.38
	Residential				
	Unmetered Rates (based on 100 watt fixture)				
810	8 Hour Lighting per kWh	$ 0.1830	$ 0.1912	$ 0.1984	$ 0.2059
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67	$ 11.67
820	12 Hour Lighting per kWh	$ 0.1830	$ 0.1912	$ 0.1984	$ 0.2059
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67	$ 11.67
830	24 Hour Lighting per kWh	$ 0.1830	$ 0.1912	$ 0.1984	$ 0.2059
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67	$ 11.67
840	Air Raid & Fire Sirens	Currently no customers in this rate category			
850	Outdoor Christmas Lighting - 5.77¢ per watt of connected load per week				
234	Customer Owned Outdoor Recreational Lighting				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 5,000 kWh	$ 0.1830	$ 0.1912	$ 0.1984	$ 0.2059
	Energy Charge per kWh for balance of kWh	$ 0.1139	$ 0.1168	$ 0.1213	$ 0.1257
	Short Term Unmetered Rates	Currently no customers in this rate category			
	Energy Charge:				
	per kWh of estimated consumption	$ 0.1830	$ 0.1912	$ 0.1984	$ 0.2059

Connection Charge:	Single-Phase	Three-Phase
A. Connecting to existing secondary voltage	$99.08	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Single-Phase	Three-Phase
(1) Up to and including 10 kVA	$148.87	$209.17
(2) 11 kVA to 15 kVA	$240.79	$301.01
(3) 16 kVA to 25 kVA	$269.20	$336.64
(4) 26 kVA to 37 kVA	$301.01	$336.64
(5) 38 kVA to 50 kVA	$336.64	$336.64
(6) 51 kVA to 75 kVA	$369.58	$523.96
(7) 76 kVA to 125 kVA	$431.07	$555.59
(8) Above 125 kVA	0	$594.94

MARITIME ELECTRIC
A FORTIS COMPANY
All our energy. All the time.

APPENDIX B

Conference Board of Canada Reports

increased the level of public debt in the province, which is still running a sizable deficit. As the government aims to balance its budget, we expect government spending to contribute little to the province's economic growth in the near term.

Outside the energy sector, the medium-term outlook for the metal mining sector is also optimistic. With the ongoing underground expansion of Voisey's Bay mine, the anticipated rise in the production of nickel and copper will contribute to a rebound of the metal mining sector in 2022.

Despite strong employment gains in 2019, the overall outlook for the labour market in Newfoundland and Labrador is subdued. Employment is expected to decline in 2020 and the labour force will continue to fall throughout the medium term. The decrease in the labour force coupled with weak household income growth will weigh heavily on consumer spending, slowing its growth to less than 0.2 per cent per year from 2020 onwards.

Prince Edward Island

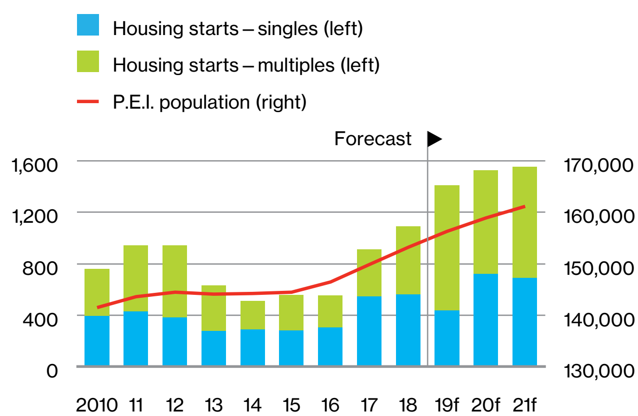
Prince Edward Island continues to outpace national economy

The economic hot streak will continue for Prince Edward Island in 2020, with growth expected to outpace the Canadian economy for a fifth year in a row. Underpinning this feat are solid population gains. A sustained influx of international immigrants has made the Island the fastest-growing province in the country and well on its way—likely a year ahead of schedule—of reaching the government's 2017 goal of 160,000 residents by 2022. The population gains are having multiple knock-on effects throughout the provincial economy. Strong demand for homes has seen housing activity boom on the Island in recent years, with another strong year expected in 2020. (See Chart 6.) Unsurprisingly, this has led to a surge in residential investment and construction activity in the province. Similarly, the transportation sector responsible for the movement of new housing materials is also seeing solid growth. Manufacturing will continue to be the most consistent performer for the Island economy, with another good year in store.

Chart 6

Demand for housing driving Island growth

(housing starts, units; population, people)



f = forecast
Sources: The Conference Board of Canada; CMHC Time Series Database.

With a more sizable population comes a larger tax base, and as such, government revenues have been higher than expected. Interestingly, spending was lower than budgeted. Combined, the stronger revenues and lower expenditures resulted in an upward revision of the surplus projection, from $14 million in Budget 2019 to

$57 million with the release of the public accounts final numbers. Going forward, the newly elected Conservative minority government should have some fiscal wiggle to pursue items on its platform that have broad appeal across parties, such as increased health care spending. When we combine these encouraging developments with promising tourism prospects, the Island will continue to outpace national growth over the near term. Following the solid growth of 3.1 per cent in 2019, we expect real GDP on the Island to grow 2.0 per cent in 2020 and 1.9 per cent in 2021.

Nova Scotia

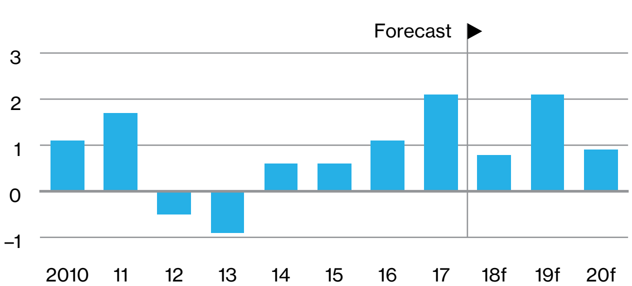
Domestic demand rises with strong population growth

Nova Scotia is forecast to grow at 2.1 per cent in 2019, its strongest pace in over a decade, before slowing to 0.9 per cent in 2020. (See Chart 7.) The positive outlook is being driven by the influx of immigrants to the province in 2018, and again this year, which is helping to buoy household demand and fill labour shortages. Stronger population growth in the province will continue to provide a base of support for consumer spending and residential construction activities over the near term.

Chart 7

Continued population growth drives growth in Nova Scotia

(real GDP at market prices, 2012$, percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Exports have continued to grow in the first eight months of this year, with continued momentum seen in seafood and lobster exports as well as rubber tires. The province's strong export performance can be attributed largely to the U.S.–China trade tensions, which has left Canadian lobster exporters to fill the heightened demand from the Chinese market. However, as is the case for the rest of Canadian trade, a weaker global economy will weigh on Nova Scotia's exports and overall growth over the near term.

An increase in homebuilding activities in Halifax is leading to a turnaround in capital spending this year. Non-residential investment will begin to support growth again over the near term, as construction on the Goldboro LNG project is expected to ramp up in 2021 (following a positive final investment decision in late 2020). The Nova Scotia government has also tabled a sizable capital budget for the current fiscal year, which will see large capital funds allocated to highway construction projects and two large hospital redevelopments within the province.

At the industry level, a pullback in offshore oil and gas operations in the province will weigh on the primary sector over the near term. Federal shipbuilding contracts and Michelin Tires' recent product investment will continue to support growth in the manufacturing sector. However, the uncertain future of Northern Pulp's proposed effluent treatment plant continues to be a downside risk to the outlook.

December 5, 2019
Provincial Medium Term
Forecast: 20 Run: 20

INDICATORS, PRINCE EDWARD ISLAND

TABLE 3: KEY ECONOMIC INDICATORS, PRINCE EDWARD ISLAND

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
RYGDPKP	G.D.P AT MARKET PRICES	5668	5733	5967	6096	6284	6408	6532	6665	6778	6891	6993	7100	7220
	(MILLIONS $2012)	1.0	1.2	4.1	2.2	3.1	2.0	1.9	2.0	1.7	1.7	1.5	1.5	1.7
RQTOP	G.D.P AT BASIC PRICES	5281	5372	5553	5700	5868	5984	6103	6232	6340	6448	6547	6651	6768
	(MILLIONS $2012)	1.4	1.7	3.4	2.6	2.9	2.0	2.0	2.1	1.7	1.7	1.5	1.6	1.8
RPYGDPP	IMPLICIT PRICE DEFLATOR -	1.080	1.115	1.122	1.156	1.178	1.200	1.223	1.248	1.274	1.299	1.324	1.347	1.371
	GDP AT MARKET PRICES (2012=1.0)	2.8	3.2	0.6	3.0	2.0	1.8	1.9	2.0	2.0	2.0	1.9	1.8	1.7
RPCPIP	CONSUMER PRICE INDEX (2002=1.0)	1.293	1.308	1.332	1.363	1.381	1.409	1.435	1.464	1.493	1.523	1.554	1.586	1.618
		-0.6	1.2	1.8	2.3	1.3	2.0	1.9	2.0	2.0	2.0	2.0	2.0	2.0
RWRP	WAGES & SALARY PER	36	38	39	39	41	42	43	44	45	46	47	48	48
	EMPLOYEE (THOUSANDS $)	2.8	5.2	1.9	1.1	4.7	2.5	2.4	2.4	2.3	2.3	1.7	1.3	1.3
RYHPIP	PRIMARY HOUSEHOLD	4324	4468	4684	4836	5084	5209	5380	5553	5753	5981	6179	6341	6508
	INCOME (MILLIONS $)	1.4	3.3	4.8	3.2	5.1	2.5	3.3	3.2	3.6	4.0	3.3	2.6	2.6
RYHDIP	HOUSEHOLD DISPOSABLE	3969	4158	4403	4507	4713	4835	4984	5130	5299	5509	5704	5870	6040
	INCOME (MILLIONS $)	2.7	4.8	5.9	2.3	4.6	2.6	3.1	2.9	3.3	4.0	3.5	2.9	2.9
RH15P	POPULATION OF LABOUR	121	122	124	126	128	130	132	134	136	138	140	141	143
	FORCE AGE	0.2	0.7	1.5	1.5	2.2	1.6	1.4	1.5	1.4	1.4	1.3	1.2	1.2
RLP	LABOUR FORCE ('000)	82	80	82	84	85	86	87	88	89	90	91	92	92
		-1.1	-1.7	1.9	2.4	1.7	1.2	0.9	1.0	1.1	1.1	1.0	0.9	0.9
RLEMP	EMPLOYMENT ('000)	73	72	74	76	77	78	79	80	80	81	82	83	84
		-1.0	-2.2	3.0	3.0	1.9	0.8	0.9	1.1	1.1	1.2	1.1	0.9	0.9
RLURP	UNEMPLOYMENT RATE	10.4	10.9	9.9	9.4	9.2	9.5	9.6	9.5	9.5	9.4	9.4	9.4	9.4
RRTP	RETAIL SALES (MILLIONS $)	2059	2209	2349	2417	2493	2532	2598	2660	2731	2809	2915	3000	3089
		2.6	7.3	6.3	2.9	3.1	1.6	2.6	2.4	2.7	2.9	3.8	2.9	3.0
RIHSP	HOUSING STARTS	558	556	911	1089	1409	1525	1553	1582	1611	1583	1530	1478	1426
	(NUMBER OF UNITS)	9.2	-0.4	63.8	19.5	29.3	8.3	1.9	1.8	1.8	-1.7	-3.3	-3.4	-3.5

		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
RYGDPKP	G.D.P AT MARKET PRICES	7335	7453	7572	7698	7824	7955	8088	8226	8363	8509	8663	8819	8979
	(MILLIONS $2012)	1.6	1.6	1.6	1.7	1.6	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8
RQTOP	G.D.P AT BASIC PRICES	6879	6994	7110	7232	7355	7483	7613	7746	7881	8023	8173	8325	8480
	(MILLIONS $2012)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.7	1.8	1.9	1.9	1.9
RPYGDPP	IMPLICIT PRICE DEFLATOR -	1.395	1.419	1.444	1.469	1.495	1.521	1.547	1.574	1.601	1.628	1.656	1.685	1.714
	GDP AT MARKET PRICES (2012=1.0)	1.8	1.8	1.7	1.8	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
RPCPIP	CONSUMER PRICE INDEX (2002=1.0)	1.650	1.684	1.718	1.752	1.788	1.824	1.861	1.898	1.937	1.976	2.016	2.056	2.098
		2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
RWRP	WAGES & SALARY PER	49	50	50	51	52	52	53	54	54	55	56	57	57
	EMPLOYEE (THOUSANDS $)	1.3	1.3	1.4	1.3	1.3	1.3	1.3	1.4	1.4	1.3	1.3	1.3	1.3
RYHPIP	PRIMARY HOUSEHOLD	6671	6844	7025	7214	7410	7610	7816	8027	8249	8474	8707	8946	9194
	INCOME (MILLIONS $)	2.5	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.8	2.7	2.8	2.7	2.8
RYHDIP	HOUSEHOLD DISPOSABLE	6210	6386	6569	6755	6948	7144	7345	7552	7768	7989	8216	8450	8692
	INCOME (MILLIONS $)	2.8	2.8	2.9	2.8	2.9	2.8	2.8	2.8	2.9	2.8	2.8	2.8	2.9
RH15P	POPULATION OF LABOUR	145	146	148	150	151	153	155	156	158	159	161	162	164
	FORCE AGE	1.1	1.2	1.1	1.1	1.1	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.9
RLP	LABOUR FORCE ('000)	93	94	95	95	96	97	98	99	99	100	101	102	103
		0.7	0.8	0.8	0.8	0.9	0.8	0.8	0.8	0.8	0.8	0.9	0.8	0.9
RLEMP	EMPLOYMENT ('000)	84	85	86	87	87	88	89	90	91	91	92	93	94
		0.8	0.8	0.8	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
RLURP	UNEMPLOYMENT RATE	9.3	9.3	9.2	9.1	9.1	9.0	8.9	8.8	8.8	8.7	8.6	8.6	8.6
RRTP	RETAIL SALES (MILLIONS $)	3179	3274	3372	3473	3578	3686	3799	3916	4039	4165	4297	4433	4576
		2.9	3.0	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2
RIHSP	HOUSING STARTS	1374	1322	1270	1218	1166	1114	1062	1010	958	906	854	802	750
	(NUMBER OF UNITS)	-3.6	-3.8	-3.9	-4.1	-4.3	-4.5	-4.7	-4.9	-5.1	-5.4	-5.7	-6.1	-6.5

December 5, 2019
Provincial Medium Term
Forecast: 20 Run: 20

TABLE 195: REAL GROSS DOMESTIC PRODUCT AT BASIC PRICES: PRINCE EDWARD ISLAND (MILLIONS, $ 2012)

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
RQCROPP	AGRICULTURE	228	244	244	243	246	249	252	255	259	262	265	269	272	276	279	283	287	290	294	298	302	306	310	314	318	322
		-0.1	6.8	0.0	-0.5	1.5	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
RQFLOGP	FORESTRY	4	5	5	5	5	5	5	5	5	5	5	5	6	6	6	6	6	6	6	6	6	6	6	7	7	7
		13.2	9.3	-4.3	8.9	-3.2	1.9	4.5	4.1	0.1	0.8	1.9	1.6	1.6	1.6	1.6	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
RQSAGFP	SUPORT ACTIVITIES FOR AGRICULTURE & FORESTRY	17	16	17	16	16	16	17	17	17	17	17	17	17	17	17	17	17	18	18	18	18	18	18	18	18	18
		1.8	-3.5	2.4	-2.9	-0.7	0.9	1.0	0.9	0.8	0.6	-0.1	0.4	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6
RQHUNTP	FISHING, TRAPPING & HUNTING	90	80	84	87	86	87	87	86	86	85	84	83	82	81	80	79	78	77	76	75	74	74	73	72	71	70
		4.6	-11.6	4.6	4.5	-1.2	0.3	0.0	-0.3	-0.5	-1.5	-1.1	-1.1	-1.1	-1.1	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
RQMINP	MINING	2	2	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3
		-30.8	5.6	47.4	-21.4	-0.5	0.2	1.9	0.6	0.4	3.0	1.8	1.0	0.6	0.7	0.8	0.9	0.9	1.0	0.9	0.8	0.9	0.9	1.0	1.0	1.0	1.0
RQMOREP	METAL MINING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0.0	0.0	0.0	0.0	-1.3	0.7	-5.5	2.2	3.6	1.8	0.0	-2.7	-3.4	0.1	0.6	0.9	-1.6	8.3	2.1	0.1	-1.7	2.4	2.2	-0.9	1.6	2.2
RQMMINP	NON-METAL MINING	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2
		-37.5	0.0	20.0	0.0	2.0	0.4	3.4	1.0	0.6	4.0	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
RQMIMFP	MINERAL FUELS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RQMSUPP	SUPPORT ACTIVITIES FOR MINING, OIL & GAS EXTRACTION	1	1	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
		-30.8	11.1	70.0	-35.3	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	-0.8	-0.5	-0.4	-0.1	-0.2	-0.1	-0.2	-0.4	-0.2	-0.4	0.0	-0.2	-0.2	-0.2
RQUTIP	UTILIES	78	80	82	86	87	88	90	91	93	94	96	97	99	101	103	105	107	109	111	114	116	118	121	124	126	129
		4.7	2.2	2.8	5.1	0.8	0.9	2.1	1.9	1.6	1.6	1.8	1.6	1.9	1.9	1.9	1.9	2.0	2.0	2.1	2.0	2.1	2.1	2.1	2.1	2.2	2.3
RQCONP	CONSTRUCTION	262	266	317	325	364	382	399	412	419	427	428	433	441	446	451	455	460	465	471	476	483	489	496	503	510	518
		-2.3	1.6	19.2	2.6	12.1	5.0	4.2	3.5	1.7	1.8	0.2	1.3	1.7	1.2	1.0	1.0	1.0	1.2	1.1	1.2	1.3	1.3	1.4	1.4	1.5	1.4
RQMANP	MANUFACTURING	518	530	556	583	610	630	645	654	665	670	677	685	693	702	711	720	729	739	749	758	769	780	791	802	814	826
		10.6	2.5	4.8	4.9	4.5	3.3	2.3	1.5	1.6	0.9	1.0	1.1	1.2	1.3	1.3	1.2	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.4	1.4
RQGDP	GOODS PRODUCING INDUSTRIES	1204	1223	1308	1351	1419	1461	1498	1526	1548	1565	1577	1594	1615	1633	1652	1670	1690	1709	1730	1751	1773	1796	1820	1844	1870	1895
		4.3	1.7	6.9	3.2	5.1	3.0	2.5	1.9	1.4	1.1	0.8	1.1	1.3	1.2	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.3
RQWRTP	WHOLESALE & RETAIL TRADE	478	491	513	523	530	533	539	544	550	557	564	571	580	588	596	605	614	623	633	642	652	662	672	682	693	705
		-3.0	2.6	4.5	2.0	1.3	0.5	1.2	0.9	1.1	1.3	1.3	1.2	1.5	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6
RQTWHOP	WHOLESALE TRADE	110	109	114	118	119	120	122	123	124	126	127	129	131	133	135	137	139	142	144	146	149	151	153	156	158	161
		-7.9	-0.9	4.2	3.7	0.6	1.1	1.5	1.0	0.9	1.1	1.4	1.3	1.6	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
RQTRETP	RETAIL TRADE	368	381	399	405	411	412	417	421	426	431	437	442	449	455	461	468	475	481	489	496	503	511	518	527	535	544
		-1.5	3.6	4.5	1.6	1.5	0.3	1.1	0.9	1.1	1.4	1.3	1.2	1.4	1.4	1.4	1.4	1.5	1.4	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6

December 5, 2019
Provincial Medium Term
Forecast: 20 Run: 20

TABLE 195: REAL GROSS DOMESTIC PRODUCT AT BASIC PRICES: PRINCE EDWARD ISLAND (MILLIONS, $ 2012)

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
RQTSCP	TRANSPORTATION &	172	179	186	192	204	208	211	215	218	221	222	225	228	230	233	236	238	240	243	245	247	250	252	254	257	259
	WAREHOUSING	4.7	3.5	4.3	3.0	6.3	2.1	1.6	1.8	1.3	1.3	0.8	1.0	1.3	1.2	1.2	1.1	1.1	0.8	1.0	0.9	1.0	0.9	0.9	1.0	0.9	0.9
RQCULP	INFORMATION & CULTURE	166	165	166	167	169	171	175	178	181	185	188	191	194	198	201	205	208	211	214	217	221	224	227	230	233	236
		4.7	-0.5	0.3	0.4	1.2	1.6	2.0	2.0	1.9	1.9	1.8	1.5	1.7	1.7	1.7	1.7	1.6	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.3
RQFIRMP	FINANCE, INSURANCE,REAL ESTATE	1020	1048	1075	1099	1125	1159	1198	1236	1274	1314	1355	1394	1436	1479	1523	1568	1613	1658	1706	1753	1801	1849	1898	1949	2001	2054
	& MANGEMENT OF COMPANIES	1.9	2.7	2.6	2.2	2.4	3.1	3.3	3.2	3.1	3.2	3.1	2.9	3.0	3.0	3.0	2.9	2.9	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7
RQIMPRP	IMPUTED RENT	554	565	579	597	608	627	647	668	690	712	732	752	773	793	814	834	855	876	896	917	938	959	980	1000	1021	1042
		2.8	2.0	2.5	3.0	1.9	3.1	3.3	3.2	3.2	3.2	2.8	2.8	2.7	2.7	2.6	2.5	2.5	2.4	2.4	2.3	2.3	2.2	2.2	2.1	2.1	2.1
RQIOTHP	OTHER FINANCE, INSURANCE,	466	483	496	502	517	532	550	568	584	603	623	642	664	686	710	733	758	783	809	836	863	890	919	949	980	1012
	REAL ESTATE & MGT OF COMPANIE	0.8	3.6	2.7	1.3	2.9	3.0	3.4	3.1	3.0	3.1	3.3	3.1	3.4	3.4	3.4	3.3	3.3	3.3	3.4	3.3	3.2	3.2	3.2	3.2	3.2	3.3
RQCBCMP	COMMERCIAL SERVICES	644	650	659	677	680	687	696	710	723	733	744	756	770	780	792	804	821	838	858	877	897	917	939	963	989	1016
		-0.9	1.1	1.4	2.7	0.4	1.2	1.3	1.9	1.8	1.5	1.5	1.6	1.8	1.3	1.5	1.6	2.1	2.2	2.3	2.2	2.3	2.3	2.4	2.6	2.7	2.8
RQPROFP	PROFESSIONAL, SCIENTIFIC &	152	155	156	155	146	142	143	144	145	145	146	146	147	147	148	148	149	149	150	150	151	151	152	153	154	156
	TECHNICAL SERVICES	6.1	1.6	0.5	-0.6	-5.4	-3.2	0.7	0.8	0.8	0.1	0.3	0.5	0.5	0.2	0.2	0.2	0.6	0.4	0.4	0.3	0.4	0.4	0.2	0.7	0.8	1.2
RQADWSP	ADMINISTRATIVE & SUPPORT AND	149	145	141	154	171	183	184	188	193	197	200	205	210	212	216	220	228	237	246	256	266	277	289	302	316	330
	WASTE MGT & REMEDIATION	-10.7	-2.7	-2.6	8.7	11.7	6.5	0.8	2.4	2.1	2.3	1.7	2.3	2.6	1.2	1.7	2.0	3.5	3.8	4.1	3.9	4.0	4.0	4.2	4.6	4.6	4.4
RQARTSP	ARTS, ENTERTAINMENTN &	56	56	59	62	58	56	58	60	63	64	67	69	72	75	78	81	84	88	91	95	99	102	106	111	115	120
	RECREATIO	-9.3	-0.7	4.8	5.5	-6.1	-3.9	3.6	4.1	4.0	2.7	3.9	4.0	4.1	4.0	4.0	3.9	4.0	3.9	4.0	3.9	3.9	3.9	3.9	4.0	4.0	4.1
RQACCOP	ACCOMMODATION & FOOD	168	174	180	186	180	183	186	191	195	198	202	205	209	213	217	221	225	229	234	238	243	247	252	257	262	267
		5.1	3.8	3.6	3.1	-3.0	1.4	2.0	2.3	2.3	1.7	2.0	1.5	1.8	1.9	1.9	1.9	1.8	1.9	1.9	2.0	1.9	1.9	2.0	1.9	1.9	1.9
RQLAUNP	OTHER SERVICES (EXCEPT	119	121	124	121	124	125	125	127	128	129	130	131	132	132	133	134	135	136	137	137	138	139	140	141	142	144
	PUBLIC ADMINISTRATION)	0.9	1.9	2.4	-1.9	2.0	0.8	0.6	0.9	0.8	0.8	0.7	0.8	0.9	0.4	0.5	0.4	0.8	0.7	0.8	0.6	0.7	0.6	0.5	0.8	0.9	1.4
RQNCSP	NON-COMMERCIAL SERVICES	921	939	955	986	1017	1033	1048	1078	1096	1120	1141	1160	1180	1200	1220	1240	1259	1278	1297	1318	1339	1360	1384	1409	1434	1458
		0.7	1.9	1.7	3.3	3.1	1.6	1.4	2.8	1.7	2.2	1.9	1.7	1.7	1.7	1.7	1.6	1.5	1.5	1.5	1.6	1.6	1.6	1.7	1.8	1.8	1.7
RQEDUCP	EDUCATIONI	391	399	406	420	429	432	435	439	445	451	458	466	474	481	488	494	501	507	513	519	525	530	536	543	549	555
		0.7	2.1	1.9	3.4	2.0	0.8	0.5	1.1	1.2	1.5	1.5	1.7	1.8	1.4	1.4	1.2	1.4	1.2	1.3	1.1	1.1	1.1	1.0	1.3	1.1	1.1
RQHEALP	HEALTHCARE & SOCIAL ASSISTAN(	530	540	548	566	589	601	613	639	651	669	682	694	706	719	732	746	758	771	784	799	814	830	848	866	885	903
		0.7	1.8	1.5	3.3	4.0	2.1	2.0	4.1	2.0	2.7	2.1	1.7	1.7	1.8	1.9	1.9	1.6	1.7	1.7	1.9	1.9	1.9	2.2	2.2	2.2	2.0
RQPADP	PUBLIC ADMINISTRATOIN	676	677	688	702	720	726	735	740	746	749	752	755	761	766	773	779	786	792	799	806	813	820	827	835	844	853
		0.3	0.1	1.7	2.1	2.6	0.8	1.2	0.8	0.7	0.4	0.3	0.5	0.7	0.8	0.8	0.8	0.9	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0
RQSRP	SERVICES PRODUCING INDUSTRIES	4075	4147	4240	4344	4443	4516	4600	4699	4786	4877	4964	5051	5147	5240	5336	5434	5537	5639	5747	5856	5967	6079	6197	6322	6449	6580
		0.6	1.8	2.2	2.4	2.3	1.7	1.8	2.2	1.8	1.9	1.8	1.7	1.9	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0
RQTOP	ALL INDUSTRIES	5281	5372	5553	5700	5868	5984	6103	6232	6340	6448	6547	6651	6768	6879	6994	7110	7232	7355	7483	7613	7746	7881	8023	8173	8325	8480
		1.4	1.7	3.4	2.6	2.9	2.0	2.0	2.1	1.7	1.7	1.5	1.6	1.8	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.7	1.8	1.9	1.9	1.9

The Conference Board of Canada

Growth Plummets, but Atlantic Bubble Helps the Island Avoid the Worst

Prince Edward Island's Two-Year Outlook

Issue briefing | December 16, 2020

Contents

Key findings

- Prince Edward Island is currently in its largest recession in decades, but it appears the worst is behind the province as we expect growth to return to pre-COVID-19 trend levels by early 2022.
- With the lowest number of COVID-19 cases in the country, the province has been able to welcome visitors from within the Atlantic bubble, which has helped mitigate the worst of the recession.
- Still, the second-quarter drop of 12 per cent will be the biggest on record and result in an overall annual contraction of 5.6 per cent in provincial GDP this year.
- The key drivers of recent growth on the Island have been tourism and immigration, both of which were severely hampered by the border closures. However, with the vaccine expected next year, we anticipate that visitors—overnight and permanent—will return to the Island in droves.
- The government has been an essential source of growth and stability during this economic crisis. Essential stimulus spending combined with a major hit to government coffers will result in a record provincial deficit of $178 million this fiscal year.

Prince Edward Island snapshot

Government background and information

Premier	Dennis King
Next election	2023
Population (2020Q3)	159,626
Government balance	–$178.1 million

Sources: The Conference Board of Canada; P.E.I. Finance; Statistics Canada.

Forecast risk

Short term
A second shutdown as a result of the surge in COVID-19 cases would halt the economic recovery.

Medium term
If federal immigration targets continue to increase, P.E.I. will likely be a prime destination thanks to the early success of the Atlantic Immigration Pilot Program.

Key economic indicators

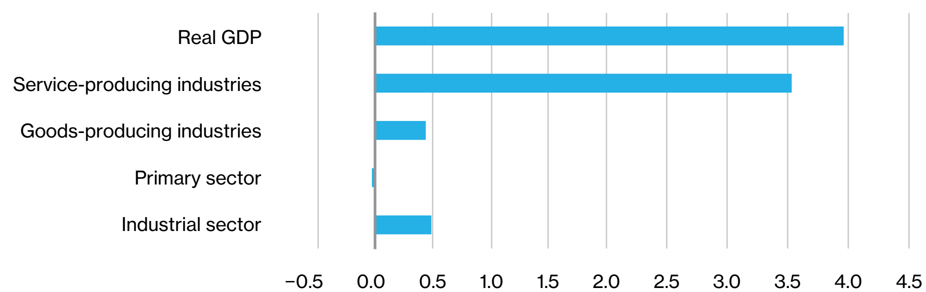
(percentage change)

	2020	2021	2022
Real GDP	–5.6	2.1	6.0
Consumer price index	0.4	2.3	2.3
Household disposable income	25.7	–11.1	–0.8
Employment	–2.6	3.0	2.0
Unemployment rate (level)	10.6	9.5	9.2
Retail sales	–2.4	3.6	4.3
Wages and salaries per employee	4.76	–0.2	1.9
Population	1.7	1.0	1.3

Shaded area represents forecast data.
Sources: The Conference Board of Canada; Statistics Canada.

Contributions to Prince Edward Island real GDP growth, 2021

(by industry/sector, percentage point; GDP, per cent)

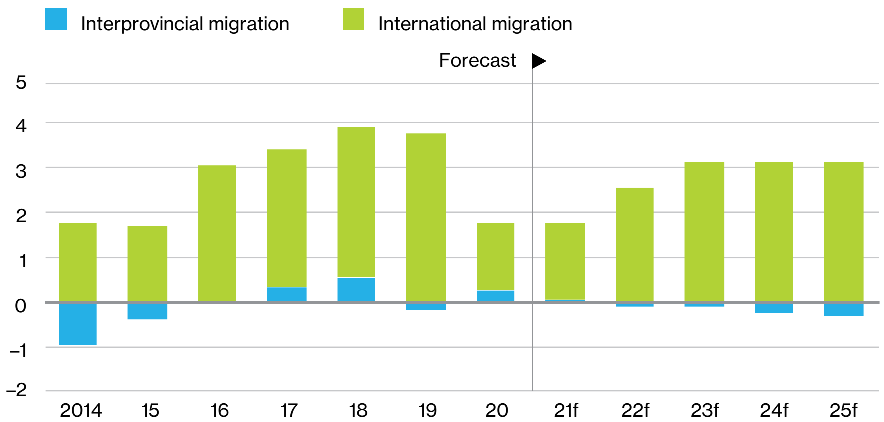


Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Prince Edward Island snapshot (cont'd)

Sources of migration

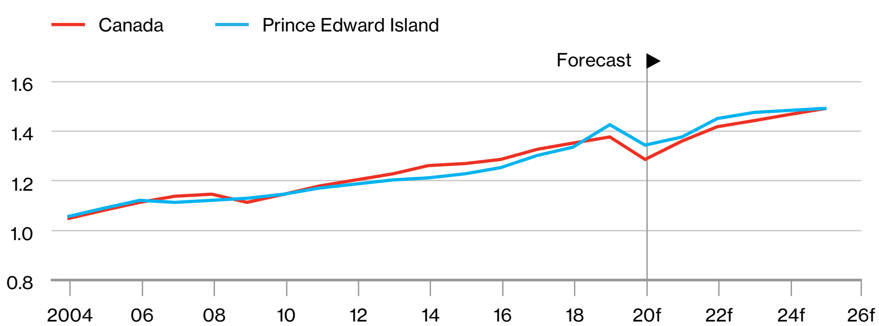
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2004 to 2025

(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Overview

Prince Edward Island is currently suffering its largest recession on record. The recent key drivers of growth, particularly immigration and tourism, have been severely hampered by the ongoing global pandemic. While the Atlantic bubble—which permits travellers to enter the Island province from any of the other three Atlantic provinces—has mitigated some of the damage, the second-quarter drop of 12 per cent remains the largest drop in provincial GDP on record. We expect that, with a vaccine available in mid-2021 and the re-opening of the United States–Canada border, improvements in tourism and immigration should help the province return to pre-COVID trend levels by early 2022.

P.E.I. had been consistently breaking annual visitor records leading into 2020 but, due to border closures and general concerns about travel, tourism understandably plummeted in the second quarter and will remain depressed in 2020. While the Atlantic bubble will help the industries that rely on tourism—notably accommodation and food services—most high-spending tourists in past years have come from across Ontario and Quebec where COVID numbers remain elevated. Despite the expectation that a vaccine will be available in mid-2021, which will result in tourism gains, it is likely that the travel industry will remain below normal levels until 2023.

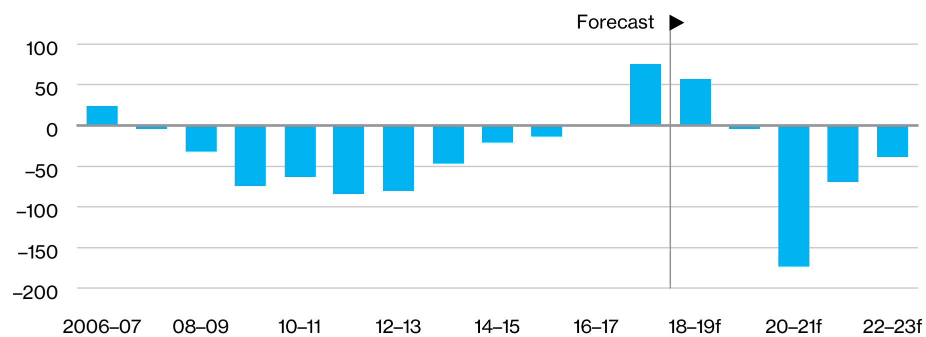
Immigration, the other solid source of growth for the Island province, has understandably taken a hit in 2020 due to travel restrictions. However, the recently announced immigration targets from the Canadian government should lead to significant increases over the next three years. While these targets may be difficult to achieve in the very near term, it is reasonable to expect that, with P.E.I.'s low COVID–19 cases, the province should see a solid boost to immigration over the near to medium term. This will aid the economic recovery through increases to household spending, resettlement activity, and demand for housing.

During the economic crisis, federal and provincial governments have been an essential source of growth, providing stimulus and helping to maintain business and consumer confidence. Provincial government measures, which include $200 million in direct and indirect support, have helped mitigate the economic damage caused by the COVID-19 pandemic. Most recently, in its September fiscal update, the province outlined its estimate for the deficit; it is expected to soar to $178 million this fiscal year due to plummeting revenues and increased stimulus measures. (See Chart 1.)

Chart 1

Revenues plummet and spending increases lead to worst deficit in Island's history

(public accounts basis, $ millions)



f = forecast

Sources: The Conference Board of Canada; P.E.I. Department of Finance; P.E.I. Budget 2020, September 2020 quarterly update.

Tourism suffers major setback

One of the main drivers of economic activity on the Island has always been tourism. Unfortunately, the industry is currently undergoing its biggest shock in history as a result of the global pandemic. Flight restrictions, or even permanent cancellations in the case of WestJet, plus self-isolation rules being implemented around the globe have completely shuttered the tourism sector.[1] Output in related tourism industries such as arts and entertainment, accommodation and food services, and information and cultural services fell to 60 per cent of its 2019 level in the second quarter. Some of the losses were gained back in the third quarter, thanks in part to the Atlantic bubble. However, until a vaccine is fully in place and confidence about travel is restored, we will not see tourism return to pre-COVID-19 levels until early 2023. This is because most high-spending tourists usually arrive from Ontario, Quebec, or the United States. But it certainly appears that the worst is behind the province, and tourism is on the slow road to recovery.

1 Pete Evans, "WestJet Shuts Down Most of Its Operations in Atlantic Canada," CBC Business News, October 14, 2020, www.cbc.ca/news/business/westjet-cuts-1.5761526.

With less demand for luxury cruises and with international leisure air travel being limited for the foreseeable future, it will take sometime for key tourism industries to recover.

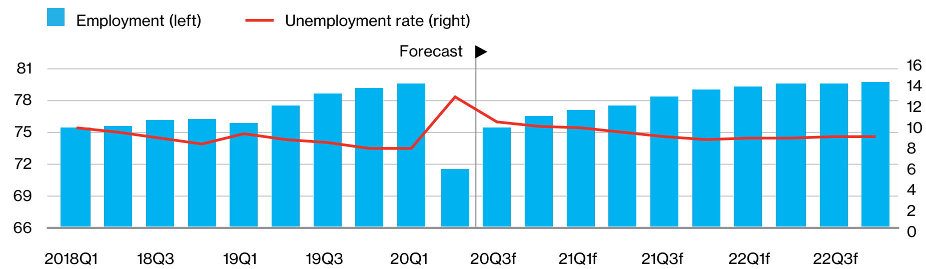
Labour markets take first step on road to recovery

The COVID-19 pandemic has acted like a wrecking ball on the Prince Edward Island labour market. The second-quarter drop of more than 8,000 jobs was the single worst quarter in labour market history for the province. While we did see the recapture of nearly 4,000 jobs in the third quarter, the remainder of the labour market's recovery to pre-COVID-19 trend levels will be much slower. This is because the affected industries are all related to tourism, which will be held back until borders reopen and social distancing is significantly less strict. Specifically, employment in information and technology, accommodation and food services, wholesale and retail trade, and transportation and warehousing make up the bulk of the lost jobs that have yet to recover. With a vaccine potentially available in mid-2021, we expect visitors to return to P.E.I., which will help boost labour demand in these hard-hit tourism-related industries. We expect employment levels will return to pre-COVID-19 trend levels by early 2022 though some jobs may likely not come back for a while longer. The employment rate, after spiking to its highest level in 20 years at 13.4 per cent in 2020, should steadily improve to 9.3 per cent by the end of next year. (See Chart 2.)

Chart 2

Labour markets on the road to recovery

(employment, 000s: unemployment rate, per cent)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Construction benefiting from build-up in housing

Population growth in Prince Edward Island has been booming since 2016. With surging immigration, the Island's population growth has far outpaced Canada's population gains over the same time period. As a consequence, there has been a housing boom on the Island province, with housing starts growing at an average annual pace of 39 per cent over 2016–19. This demand for new housing has been a boon to the construction sector. Finalizing the completion of the huge number of 2019 homes will help in 2020 despite the pandemic-related shutdown in April and part of May. This boom to housing-related construction combined with the construction of a solar power farm in Summerside implies that the industry is in for a big year.[2] Overall output in construction will grow by 15 per cent in 2020 before dropping slightly in 2021.

While immigration takes a pause due to the pandemic, we are optimistic that population gains will return to the record pre-COVID-19 pace in short order. (See "Pandemic pauses immigration temporarily, but it should return to a record pace.") This should provide an upside risk to the construction industry over the medium term.

2 Sam Juric, "$69M Plan for Summerside Solar Farm Announced Tuesday," CBC News, January 14, 2020. www.cbc.ca/news/canada/prince-edward-island/pei-solar-farm-summerside-1.5426227.

Government facing significant deficit

During economic crises such as the one Canada is currently facing with the COVID-19 pandemic, citizens often look to their government as a source of confidence and stability. In addition to federal support measures such as the Canada Emergency Recovery Benefit (CERB) and Canada Emergency Wage Subsidy (CEWS), the P.E.I. government also added support for Islanders. On June 17, the province released its delayed spring budget, which outlined the ways in which the government will continue to help mitigate the impact of the pandemic on Islanders.[3] To help businesses, the province lowered the small business tax from 2 per cent to 1 per cent and provided nearly $40 million in direct support, as well as over $100 million in loans and working capital (including $50 million for tourism). With the release of the September fiscal update, total expenditures are expected to grow by 12 per cent—more than $180 million higher than initial estimates for 2020–21 in Budget 2019. The spike in expenditures will lead to the biggest deficit in the Island's history—$178 million. The province will run a smaller deficit of $70 million next year as the economy recovers and temporary support measures are removed.

3 Government of Prince Edward Island, *Budget Address* (Charlottetown: Government of Prince Edward Island, 2020), www.princeedwardisland.ca/sites/default/files/publications/budgetaddress2020weben.pdf.

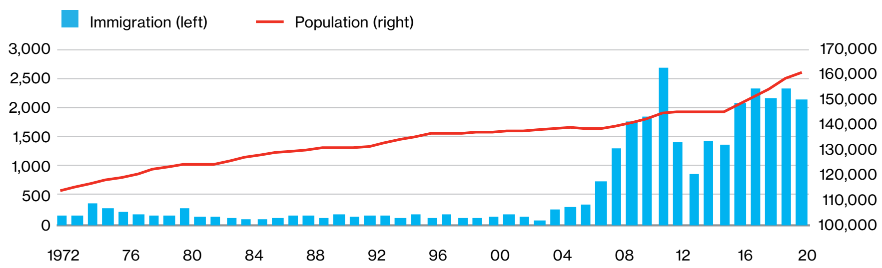
Pandemic pauses immigration temporarily, but it should return to a record pace

Before the global pandemic, Prince Edward Island was welcoming record numbers of immigrants each year. Interestingly, this increased focus on immigration began in earnest after the previous Canadian recession in 2008–09. Since then, the province has averaged over 1,800 immigrants annually, with the province welcoming over 2,000 immigrants per year since 2016. This is significantly higher than the average annual immigration of 227 between 1971 and 2008. (See Chart 3.) Predictably, this surge in immigration has fuelled economic growth on the Island. With booming housing starts, household consumption has been soaring. In fact, P.E.I. led the country in economic growth over the 2016–19 period.

Chart 3

Immigration driving population boom on the Island

(immigration and population, persons*)



* as of July 1

Sources: The Conference Board of Canada; Statistics Canada.

However, with border closures in place, immigration to P.E.I. unsurprisingly stalled for a few months between March and July of 2020. However, this has proven to be short-lived as the government has already seen surges in immigration since August.[4] And, if all goes well, P.E.I. should not see a slowdown in immigration levels any time soon. This is because the Canadian government recently announced record targets for immigration, with Immigration, Refugees and Citizenship Canada (IRCC) looking to bring in 401,000 immigrants in 2021; 411,000 in 2022; and 421,000 in 2023.[5] Even if P.E.I. welcomed its share of Canadian immigrants prior to the pandemic, the province would increase its annual intake to over 3,000 by 2023. Prince Edward Island could potentially see an even-higher share of Canada's immigrants due to recent success with welcoming and resettling new immigrants through the Atlantic Immigration Pilot Program.[6]

However, we should not understate the risks associated with these announcements. First, Canada could easily miss these targets in light of the uncertainty of the global pandemic as other countries struggle with second waves and further shutdowns. And second, retaining these immigrants will be a big challenge for the province. While the 2018 closure of the entrepreneur program—with its unfortunate loophole enabling newcomers to pay a fee and move to another province—will certainly help retain immigrants in Prince Edward Island, it still remains a possibility that immigrants look elsewhere in Canada for their long-term plans.[7] Regardless, immigration will be a key part of the province's economic prospects for years to come.

Download forecast tables

4 Colin Singer, "Prince Edward Island Draw Targets: 345 Skilled Worker and Business Candidates," Canada Immigration News, September 21, 2020, www.cimmigrationnews.com/prince-edward-island-draw-targets-345-skilled-worker-and-business-candidates/.

5 Immigration, Refugees and Citizenship Canada, "Notice–Supplementary Information for the 2021–2023 Immigration Levels Plan," October 30, 2020, www.canada.ca/en/immigration-refugees-citizenship/news/notices/supplementary-immigration-levels-2021-2023.html.

6 Kareem El-Assal, "Atlantic Canada's Immigration Revolution Continues," CIC News, February 21, 2020, www.cicnews.com/2020/02/atlantic-canadas-immigration-revolution-continues-0213710.html#gs.kqnqf2.

7 Kevin Yarr, "Citing Concerns, P.E.I. Shutting Down PNP's Immigrant Entrepreneur Program," CBC News, September 12, 2018, www.cbc.ca/news/canada/prince-edward-island/pei-pnp-entrepreneur-program-closed-1.4820072.

Methodology

This issue briefing examines the economic outlook for Prince Edward Island, including gross domestic product, output by industry, and labour market conditions. It includes a forecast for the province's economic indicators and compares its GDP against the country's overall. The outlook is updated quarterly using The Conference Board of Canada's economic model of provincial economics.

The forecast was completed November 11, 2020.

Acknowledgements

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Growth Plummets, but Atlantic Bubble Helps the Island Avoid the Worst: Prince Edward Island's Two-Year Outlook—December 2020
The Conference Board of Canada

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January 28, 2021
Provincial Medium Term
Forecast: 20203 Run: 20203

TABLE 3: KEY ECONOMIC INDICATORS, PRINCE EDWARD ISLAND

		2020Q1	2020Q2	2020Q3	2020Q4	2021Q1	2021Q2	2021Q3	2021Q4	2022Q1	2022Q2	2022Q3	2022Q4
RYGDPP	G.D.P AT MARKET PRICES	7662	6781	7034	7208	7288	7356	7579	7787	7932	8061	8159	8259
	(MILLIONS $)	0.3	-11.5	3.7	2.5	1.1	0.9	3.0	2.7	1.9	1.6	1.2	1.2
RYGDPKP	G.D.P AT MARKET PRICES	6875	6056	6149	6288	6333	6372	6530	6675	6769	6845	6897	6947
	(MILLIONS $2007)	0.5	-11.9	1.5	2.2	0.7	0.6	2.5	2.2	1.4	1.1	0.8	0.7
RQTOP	G.D.P AT BASIC PRICES	6089	5604	5770	5821	5919	5975	6106	6211	6258	6304	6338	6372
	(MILLIONS $2007)	-0.8	-8.0	3.0	0.9	1.7	0.9	2.2	1.7	0.8	0.7	0.5	0.5
RPYGDPP	IMPLICIT PRICE DEFLATOR -	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	GDP AT BASIC PRICES (2007=1.0)	-0.1	0.5	2.2	0.2	0.4	0.3	0.5	0.5	0.4	0.5	0.5	0.5
RPCPIP	CONSUMER PRICE INDEX (2002=1.0)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5
		-0.1	-1.4	1.2	1.5	0.3	0.1	0.6	0.7	0.4	0.6	0.7	0.5
RWRP	WAGES & SALARY PER EMPLOYEE	41.9	45.1	44.2	43.5	43.4	43.5	43.6	43.8	44.1	44.3	44.5	44.8
	(THOUSANDS $)	-0.5	7.6	-2.0	-1.4	-0.2	0.2	0.2	0.5	0.6	0.6	0.5	0.5
RYHPIP	PRIMARY HOUSEHOLD INCOME (MILLIC	5328	5176	5348	5381	5441	5498	5570	5639	5699	5752	5789	5830
		0.8	-2.8	3.3	0.6	1.1	1.0	1.3	1.2	1.1	0.9	0.6	0.7
RYHDIP	HOUSEHOLD DISPOSABLE INCOME	5042	6483	6529	6177	5560	5474	5249	5259	5280	5324	5363	5403
	(MILLIONS $)	3.0	28.6	0.7	-5.4	-10.0	-1.5	-4.1	0.2	0.4	0.8	0.7	0.7
RH15P	POPULATION OF LABOUR	130	131	132	132	132	133	133	134	134	135	135	136
	FORCE AGE	0.4	0.5	0.5	0.1	0.2	0.3	0.4	0.4	0.5	0.4	0.4	0.4
RLP	LABOUR FORCE ('000)	87	83	85	85	86	86	87	87	87	88	88	88
		0.5	-4.8	2.5	1.0	0.5	0.2	0.5	0.5	0.5	0.3	0.2	0.2
RLEMP	EMPLOYMENT ('000)	80	72	76	77	77	78	79	79	79	80	80	80
		0.5	-10.3	5.4	1.6	0.7	0.6	1.1	0.8	0.3	0.4	0.1	0.1
RLURP	UNEMPLOYMENT RATE	8.0	13.4	10.8	10.3	10.1	9.8	9.2	9.0	9.1	9.1	9.2	9.3
RRTP	RETAIL SALES (MILLIONS $)	2522	2269	2504	2456	2493	2513	2532	2568	2588	2623	2653	2680
		-0.1	-10.0	10.4	-1.9	1.5	0.8	0.7	1.4	0.8	1.3	1.1	1.0
RIHSP	HOUSING STARTS (NUMBER OF UNITS)	899	1487	1678	1204	1326	1405	1372	1464	1471	1478	1486	1493
		-47.8	65.4	12.8	-28.2	10.1	6.0	-2.3	6.7	0.5	0.5	0.5	0.5

January 28, 2021
Provincial Medium Term
Forecast: 20203 Run: 20203

TABLE 3: KEY ECONOMIC INDICATORS, PRINCE EDWARD ISLAND

	2020	2021	2022	2023Q1	2023Q2	2023Q3	2023Q4	2024Q1	2024Q2	2024Q3	2024Q4	2025Q1	2025Q2	2025Q3	2025Q4	2023	2024	2025
G.D.P AT MARKET PRICES	7171	7503	8103	8332	8385	8445	8498	8541	8594	8632	8689	8744	8800	8868	8930	8415	8614	8835
(MILLIONS $)	-3.7	4.6	8.0	0.9	0.6	0.7	0.6	0.5	0.6	0.4	0.7	0.6	0.6	0.8	0.7	3.9	2.4	2.6
G.D.P AT MARKET PRICES	6342	6477	6864	6971	6980	6988	6994	6995	7002	6995	7004	7011	7020	7033	7045	6983	6999	7027
(MILLIONS $2007)	-5.6	2.1	6.0	0.4	0.1	0.1	0.1	0.0	0.1	-0.1	0.1	0.1	0.1	0.2	0.2	1.7	0.2	0.4
G.D.P AT BASIC PRICES	5821	6053	6318	6404	6424	6447	6469	6484	6503	6513	6535	6557	6577	6598	6618	6436	6509	6587
(MILLIONS $2007)	-3.8	4.0	4.4	0.5	0.3	0.4	0.3	0.2	0.3	0.1	0.4	0.3	0.3	0.3	0.3	1.9	1.1	1.2
IMPLICIT PRICE DEFLATOR -	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.2	1.2	1.3
GDP AT BASIC PRICES (2007=1.0)	2.1	2.4	1.9	0.5	0.5	0.6	0.5	0.5	0.5	0.6	0.5	0.5	0.5	0.6	0.5	2.1	2.1	2.2
CONSUMER PRICE INDEX (2002=1.0)	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.5	1.5	1.5
	0.4	2.3	2.3	0.4	0.4	0.7	0.5	0.4	0.5	0.6	0.5	0.4	0.5	0.7	0.5	2.1	2.0	2.0
WAGES & SALARY PER EMPLOYEE	43.7	43.6	44.4	45.0	45.2	45.5	45.7	45.9	46.1	46.4	46.6	46.9	47.1	47.4	47.6	45.3	46.3	47.2
(THOUSANDS $)	4.7	-0.2	1.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	2.1	2.0	2.1
PRIMARY HOUSEHOLD INCOME (MILLIC	5308	5537	5768	5884	5922	5962	6003	6048	6089	6133	6181	6236	6285	6336	6387	5943	6113	6311
	2.9	4.3	4.2	0.9	0.6	0.7	0.7	0.8	0.7	0.7	0.8	0.9	0.8	0.8	0.8	3.0	2.9	3.2
HOUSEHOLD DISPOSABLE INCOME	6058	5385	5343	5437	5472	5511	5548	5585	5624	5665	5708	5722	5763	5807	5849	5492	5645	5785
(MILLIONS $)	25.7	-11.1	-0.8	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.3	0.7	0.8	0.7	2.8	2.8	2.5
POPULATION OF LABOUR	131	133	135	137	137	138	138	139	139	140	141	141	142	142	143	137	140	142
FORCE AGE	2.0	1.2	1.8	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	1.7	1.6	1.6
LABOUR FORCE ('000)	85	86	88	88	89	89	89	89	89	89	90	90	90	90	90	89	89	90
	-0.6	1.7	1.6	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.0	0.8	0.7
EMPLOYMENT ('000)	76	78	80	80	80	80	80	80	81	81	81	81	81	81	82	80	81	81
	-2.6	3.0	2.0	0.2	0.1	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.6	0.6	0.8
UNEMPLOYMENT RATE	10.6	9.5	9.2	9.4	9.5	9.6	9.6	9.7	9.7	9.8	9.7	9.7	9.7	9.7	9.6	9.5	9.7	9.7
RETAIL SALES (MILLIONS $)	2438	2526	2636	2703	2724	2749	2773	2790	2805	2822	2843	2862	2879	2901	2922	2737	2815	2891
	-2.4	3.6	4.3	0.9	0.8	0.9	0.9	0.6	0.6	0.6	0.7	0.6	0.6	0.8	0.7	3.8	2.8	2.7
HOUSING STARTS (NUMBER OF UNITS)	1317	1392	1482	1500	1502	1503	1504	1506	1491	1475	1469	1464	1458	1452	1446	1502	1485	1455
	-12.4	5.7	6.5	0.5	0.1	0.1	0.1	0.1	-1.0	-1.0	-0.4	-0.4	-0.4	-0.4	-0.4	1.4	-1.1	-2.1

APPENDIX C

Variance Analysis
2019 to 2021 Actuals and 2022 to 2025 Forecasts

OVERVIEW

The following variance analysis is provided to support the forecast energy supply costs, transmission and distribution costs, and general and administrative costs included in the revenue requirement for the rate-setting period of 2023 to 2025. The variance analysis is comprised of: (i) actual costs incurred in 2019 to 2021 compared to forecast; (ii) forecast costs for 2022 compared to the prior year actuals and forecast; and (iii) forecast costs for 2023 to 2025 compared to the prior year forecast.

C.1 Energy Supply Costs

Table C-1 provides a summary of the energy supply costs for 2019 to 2025.

TABLE C-1
Energy Supply Costs by Source ($000)

Description	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Point Lepreau	24,442	23,985	25,758	24,529	25,481	24,661	25,647
Renewables	24,599	24,958	23,658	24,472	26,635	37,187	50,637
EPA with NBEM:							
Firm Energy	59,046	65,739	73,305	86,057	81,978	77,269	65,475
Secure/Assured Energy	8,725	4,759	6,042	478	124	-	-
Ancillary and Other Services	(3)	207	(606)	-	-	-	-
Company-Owned Generation:							
CTGS	1,440	1,173	802	289	-	-	-
CT3	598	429	650	815	1,164	1,351	1,596
CT1 and CT2	310	313	426	608	607	675	893
Energy Control Centre	952	949	1,000	1,127	1,106	1,154	1,206
Interconnection Costs	4,588	4,602	4,986	4,798	4,605	4,631	4,653
Other NB Power Charges[1]	1,495	1,500	1,504	1,629	1,753	1,761	1,793
Provincial Debt Repayment Costs	-	-	-	-	4,103	5,411	5,457
Other Energy Supply Costs[2]	828	905	1,020	1,228	1,330	1,384	1,441
Total	**127,020**	**129,519**	**138,545**	**146,030**	**148,886**	**155,484**	**158,798**

[1] Other NB Power charges are NB facilities rental and transmission services.
[2] Other energy supply costs are insurance, property tax and employee training.

C.1.1 Point Lepreau

The Point Lepreau Nuclear Generating facility ("Point Lepreau") provides 29 megawatts ("MW") of contracted base load under a Participation Agreement with NB Power. Table C-2 provides historical costs for 2019 to 2021.

TABLE C-2
Point Lepreau Energy Supply Costs
Historical Results ($000, except %)

2019				2020				2021			
Forecast	**Actual**	**Variance**		**Forecast**	**Actual**	**Variance**		**Forecast**	**Actual**	**Variance**	
23,986	24,442	456	*2%*	24,356	23,985	(371)	*(2)%*	24,612	25,758	1,146	*5%*

Point Lepreau costs in 2019 and 2020 did not vary materially from forecast. The 2021 variance was primarily due to three unplanned outages totalling 100 days that resulted in increased maintenance and repair costs of $1.6 million partially offset by lower-than-planned fuel and cost of capital of $0.5 million.

Table C-3 provides the forecast for 2022 to 2025.

TABLE C-3
Point Lepreau Energy Supply Costs
2022 and GRA Forecast ($000, except %)

2022					2023			2024			2025		
Forecast	**Variance vs Prior Year Actual**		**Variance vs Prior Year Forecast**		**Forecast**	**Variance vs Prior Year Forecast**		**Forecast**	**Variance vs Prior Year Forecast**		**Forecast**	**Variance vs Prior Year Forecast**	
24,529	(1,229)	*(5)%*	(83)	*-%*	25,481	952	*4%*	24,661	(820)	*(3)%*	25,647	986	*4%*

The 2022 to 2025 forecasts are based on the NB Power board-approved budgets provided to the Company in the fall of 2021, including a 60-day planned maintenance outage in 2022 and a 50-day planned maintenance outage in 2024.

C.1.2 Renewables

This category includes contracted wind generation of 92.5 MW with the Prince Edward Island Energy Corporation ("PEIEC"), an additional 80 MW of wind and solar generation expected to be in-service during the rate-setting period, and solar generation purchased from net metering customers.

Table C-4 provides historical costs for 2019 to 2021.

TABLE C-4
Renewable Energy Supply Costs
Historical Results ($000, except %)

	2019			2020			2021		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Commercial Wind and Solar	25,236	24,276	(960)	25,534	24,548	(986)	35,499	22,858	(12,641)
Other[3]	203	323	120	300	410	110	93	800	707
Total	**25,439**	**24,599**	**(840)**	**25,834**	**24,958**	**(876)**	**35,592**	**23,658**	**(11,934)**
Variance %			*(3)%*			*(3)%*			*(34)%*

The 2019 and 2020 commercial wind and solar variances were primarily the result of lower-than-planned production from the commercial wind facilities due to the maintenance of aging facilities. The 2021 commercial wind and solar variance was due to a delay in the in-service date of the proposed 30 MW Eastern PEI wind farm. This wind farm was expected to be in-service on January 1, 2021, and has been delayed to January 1, 2024.

The other variances were due to a higher-than-planned volume of roof-top solar installations, particularly since Provincial Government incentives were launched in mid-2020, which had not been contemplated when the forecasts were prepared.

Table C-5 provides the forecasts for 2022 to 2025.

[3] Other refers to roof-top solar installations.

Table C-5 Renewable Energy Supply Costs 2022 and GRA Forecast ($000, except %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Commercial Wind and Solar	23,185	327	(12,314)	24,760	1,575	34,882	10,122	47,867	12,985
Other	1,287	487	1,194	1,875	588	2,305	430	2,770	465
Total	**24,472**	**814**	**(11,120)**	**26,635**	**2,163**	**37,187**	**10,552**	**50,637**	**13,450**
Variance %		*3%*	*(31)%*		*9%*		*40%*		*36%*

The 2022 commercial wind and solar variance compared to the prior year actual reflects the annual Consumer Price Index ("CPI") increase in the price of wind per the Power Purchase Agreements, and an expected increased output as a result of completed maintenance. The 2022 variance compared to the prior year forecast is primarily the result of the delayed in-service date of the proposed 30 MW Eastern PEI wind farm.

The 2023 to 2025 commercial wind and solar forecasts reflect the annual CPI increases in the price of wind along with the proposed Slemon Park solar micro-grid expected to be in-service on January 1, 2023, the proposed 30 MW wind farm in Eastern PEI expected to be in-service on January 1, 2024 and the proposed 40 MW wind farm expected to be in-service on January 1, 2025.

The other variances are primarily the result of improved forecast assumptions around the net metering credits purchased from customers and the continued increase in roof-top solar installations supported by Provincial Government incentive programs.

C.1.3 EPA with NBEM

The Energy Purchase Agreement ("EPA") with New Brunswick Energy Marketing ("NBEM") provides energy pricing in three tiers. The first tier, firm energy purchases, is used to supplement the energy provided by Point Lepreau and on-Island wind generation to meet Maritime Electric's forecast load requirement. The second and third tiers, which are referred to as secure and assured energy purchases, respectively, are used when Maritime Electric's energy needs exceed the contractual limit for firm energy, and both can be curtailed based on predefined situations with varying notice periods. Maritime Electric is responsible for the capacity to provide back-up energy for the second and third tier energy purchases.[4]

Ancillary services are set out in NB Power's Open Access Transmission Tariff ("OATT") and include: load following, regulation, imbalance, spinning reserve, non-spinning reserve, reactive power supply and voltage control. The rates for ancillary services vary based on NB Power's costs to administer and supply these services and on the Company's peak load as a percentage of the peak load in the Maritimes area, as ancillary services are allocated based on the Company's share of the Maritime peak load.

Other refers to a variety of miscellaneous charges, the largest of which is the provision of off-Island energy purchases during times when the EPA has been curtailed.[5] This category also includes the off-Island sale of energy when requested.[6] Maritime Electric does not forecast for the off-Island sale of energy.

Table C-6 provides the historical energy supply costs under the EPA for 2019 to 2021.

TABLE C-6
EPA - Energy Supply Costs
Historical Results ($000, except %)

	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Firm	57,631	59,046	1,415	64,635	65,739	1,104	62,708	73,305	10,597
Secure/ Assured	9,941	8,725	(1,216)	5,289	4,759	(530)	3,906	6,042	2,136
Ancillary and Other Services[7]	485	(3)	(488)	429	207	(222)	910	(606)	(1,516)
Total	**68,057**	**67,768**	**(289)**	**70,353**	**70,705**	**352**	**67,524**	**78,741**	**11,217**
Variance %			*-%*			*1%*			*17%*

[4] CT3 provides capacity for secure energy purchases, and CT1 and CT2 provide some capacity for assured energy purchases and non-spinning ancillary services.

[5] When subject to curtailment, on-Island generation is used to supply replacement energy if it is cheaper than off-Island replacement energy.

[6] On occasion, Maritime Electric is required to generate electricity to supply NB Power or Nova Scotia Power, in which case the full cost of generation is recovered.

[7] Actual amounts that are credits signify that the recovery of generation costs to supply energy off-Island exceeded the cost of ancillary services.

EPA energy supply costs in 2019 and 2020 did not vary materially from forecast.

The 2021 increase over the forecast was a result of three unplanned outages at Point Lepreau along with the postponed in-service date for the 30 MW wind farm in Eastern PEI, which had been planned for January 1, 2021 at the time the forecast was prepared. These increases were partially offset by the impact of lower-than-expected sales.

Table C-7 provides the forecast energy supply costs under the EPA for 2022 to 2025.

TABLE C-7
EPA – Energy Supply Costs
2022 and GRA Forecast ($000, except %)

	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Firm	86,057	12,752	23,349	81,978	(4,079)	77,269	(4,709)	65,475	(11,794)
Secure/ Assured	478	(5,564)	(3,428)	124	(354)	-	(124)	-	-
Ancillary Services and Other	-	606	(910)	-	-	-	-	-	-
Total	**86,535**	**7,794**	**19,011**	**82,102**	**(4,433)**	**77,269**	**(4,833)**	**65,475**	**(11,794)**
Variance %		*10%*	*28%*		*(5)%*		*(6)%*		*(15)%*

The 2022 increases over the prior year actual and forecast reflect: (i) a forecast 5.4 per cent increase in sales over the prior year that will require increased energy purchases; and (ii) an increase in the EPA contract price. The 2022 variances also reflect approximately $5.6 million of energy supply that was purchased as secure or assured energy in 2021 and forecast as firm energy in 2022 due to an increase in the contracted firm energy amount for 2022.[8]

The 2023 decrease is primarily related to a planned outage at Point Lepreau in 2022 and no planned outages in 2023, which is partially offset by an increase in the EPA contract price.

[8] Unscheduled outages at Point Lepreau in 2021 resulted in higher secure/assured energy purchases related to replacement energy. Because the 2022 outage at Point Lepreau is planned the replacement energy will be purchased as firm energy.

The 2024 decrease is primarily due to the 30 MW wind farm expected to be in-service on January 1, 2024 and a decrease in the EPA contract price, partially offset by replacement energy purchases for a 50-day planned outage at Point Lepreau.

The 2025 decrease is primarily due to the 40 MW wind farm expected to be in-service on January 1, 2025.

C.1.4 Company-Owned Generation

CTGS

The Charlottetown Thermal Generating Station ("CTGS") units were placed into warm, long-term layup effective March 1, 2019 and continued to be available to generate as required until December 31, 2021, at which point the units were retired. However, during this period the units were not required to be operated.

Table C-8 provides the historical costs related to the CTGS for 2019 to 2021.

TABLE C-8
CTGS Costs
Historical Results ($000, except %)

	2019			2020			2021		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	1,246	740	(506)	671	641	(30)	647	382	(265)
Contractors	60	55	(5)	39	36	(3)	54	32	(22)
Non-labour	403	284	(119)	255	199	(56)	315	164	(151)
Subtotal	**1,709**	**1,079**	**(630)**	**965**	**876**	**(89)**	**1,016**	**578**	**(438)**
Fuel	536	361	(175)	774	297	(477)	319	224	(95)
Total	**2,245**	**1,440**	**(805)**	**1,739**	**1,173**	**(566)**	**1,335**	**802**	**(533)**
Variance %			*(36)%*			*(33)%*			*(40)%*

The 2019, 2020 and 2021 variances were driven by the impact of the CTGS being placed in long-term layup mode beginning in 2019. The full extent to which CTGS staff could be reassigned to other areas of the Company and the decrease in contractor and non-labour costs were not precisely known when the forecasts were prepared.

CTGS fuel costs relate to heating the plant building and were lower than expected due to warmer temperatures during those heating seasons. In addition, lower-cost electric heating was used when possible, rather than operating a boiler for heating.

Table C-9 provides the forecast costs related to the CTGS for 2022 to 2025.

TABLE C-9
CTGS Costs
2022 and GRA Forecast ($000, expect %)

	2022			2023		2024		2025	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Labour	139	(243)	(508)	-	(139)	-	-	-	-
Contractors	-	(32)	(54)	-	-	-	-	-	-
Non-labour	-	(164)	(315)	-	-	-	-	-	-
Subtotal	**139**	**(439)**	**(877)**	**-**	**(139)**	**-**	**-**	**-**	**-**
Fuel	150	(74)	(169)	-	(150)	-	-	-	-
Total	**289**	**(513)**	**(1,046)**	**-**	**(289)**	**-**	**-**	**-**	**-**
Variance %		*(64)%*	*(78)%*		*(100)%*		*-%*		*-%*

The CTGS units were officially retired on December 31, 2021. The 2022 forecast reflects labour to maintain and secure the facility and fuel to supplement plant heating until the equipment associated with the operation of combustion turbine #3 (“CT3”) is removed from the plant building.[9]

CT3

The 50 MW combustion turbine, CT3, is forecast to be used for stand-by and emergency purposes with a provisional amount of generation that allows for periods of curtailment of contract energy and transmission curtailment in New Brunswick. This facility backstops the secure energy component of the EPA.

[9] Maritime Electric assumed that Commission approval to construct a building to house the CT3 equipment would be granted in time to avoid the need to heat the plant building beyond 2022.

Table C-10 provides the historical costs related to the CT3 for 2019 to 2021.

TABLE C-10 CT3 Costs Historical Results ($000, except %)									
	2019			**2020**			**2021**		
Description	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	84	130	46	179	214	35	106	167	61
Contractors	160	-	(160)	2	2	-	-	2	2
Non-labour	117	253	136	109	79	(30)	201	63	(138)
Subtotal	**361**	**383**	**22**	**290**	**295**	**5**	**307**	**232**	**(75)**
Fuel	237	215	(22)	241	134	(107)	473	418	(55)
Total	**598**	**598**	**-**	**531**	**429**	**(102)**	**780**	**650**	**(130)**
Variance %			*-%*			*(19)%*			*(17)%*

The 2019 costs did not vary from forecast. The 2019 forecast reflected fuel tank inspection costs of $140 thousand as contractor costs, which was actually recorded as non-labour costs.

The 2020 and 2021 costs did not vary materially from forecast. Nonetheless, fuel costs in 2020 were lower than forecast as CT3 was operated less than expected and non-labour costs in 2021 reflect lower-than-expected materials costs related to planned maintenance work.

Table C-11 provides the forecast costs related to the CT3 for 2022 to 2025.

TABLE C-11 CT3 Costs 2022 and GRA Forecast ($000, except %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Labour	222	55	116	205	(17)	170	(35)	332	162
Contractors	30	28	30	-	(30)	-	-	-	-
Non-labour	276	213	75	264	(12)	296	32	282	(14)
Subtotal	**528**	**296**	**221**	**469**	**(59)**	**466**	**(3)**	**614**	148
Fuel	287	(131)	(186)	695	408	885	190	982	97
Total	**815**	**165**	**35**	**1,164**	**349**	**1,351**	**187**	**1,596**	**245**
Variance %		*25%*	*4%*		*43%*		*16%*		*18%*

The 2022 variances compared to the prior year actual and forecast are mainly associated with higher labour and non-labour costs to reflect the retirement of the CTGS units and costs previously shared between the four generation assets now allocated to the three remaining generation assets.

The 2022 to 2025 forecasts for fuel costs are based on the generation of 1.2 gigawatt hours ("GWh") in each of 2022, 2023 and 2024 and 2.0 GWh in 2025, which includes testing and required generation to meet load requirements. The forecast fuel price is based on the US Energy Information Administration Forecast of future projected fuel prices at the time Maritime Electric's forecast was prepared.[10]

The labour and non-labour forecasts for 2023 to 2025 reflect inflationary increases offset by labour savings in 2023 and 2024 as employees are temporarily reassigned to CTGS decommissioning activities. The 2025 labour forecast reflects employees returning to CT3 maintenance and production duties.

[10] US Energy Information Administration Forecast is released once a year and was dated April 2022.

CT1 and CT2

The 15 MW and 25 MW combustion turbines, CT1 and CT2, respectively, are forecast to be used for stand-by and emergency purposes with a provisional amount of generation that allows for periods of curtailment of contract energy and transmission curtailment in New Brunswick. These facilities backstop the assured energy component of the EPA.

Table C-12 provides the historical costs related to the CT1 and CT2 for 2019 to 2021.

TABLE C-12
CT1 and CT2 Costs
Historical Results ($000, except %)

	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Labour	159	181	22	213	223	10	156	220	64
Contractors	3	2	(1)	1	-	(1)	4	-	(4)
Non-labour	37	27	(10)	39	24	(15)	64	47	(17)
Subtotal	**199**	**210**	**11**	**253**	**247**	**(6)**	**224**	**267**	**43**
Fuel	156	100	(56)	139	66	(73)	349	159	(190)
Total	**355**	**310**	**(45)**	**392**	**313**	**(79)**	**573**	**426**	**(147)**
Variance %			*(13)%*			*(20)%*			*(26)%*

The 2019, 2020 and 2021 costs did not vary materially from forecast. Nonetheless, in 2021 the units generated 0.36 GWh of energy compared to a forecast of 0.55 GWh, resulting in lower-than-planned fuel costs.

Table C-13 provides the forecast costs related to the CT1 and CT2 for 2022 to 2025.

TABLE C-13 CT1 and CT2 Costs 2022 and GRA Forecast ($000, except %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Labour	282	62	126	250	(32)	228	(22)	406	178
Contractors	4	4	-	4	-	5	1	5	-
Non-labour	107	60	43	72	(35)	73	1	77	4
Subtotal	**393**	**126**	**169**	**326**	**(67)**	**306**	**(20)**	**488**	182
Fuel	215	56	(134)	281	66	369	88	405	36
Total	**608**	182	**35**	**607**	**(1)**	**675**	**68**	**893**	**218**
Variance %		*43%*	*6%*		*-%*		*11%*		*32%*

The 2022 variances compared to the prior year actual and forecast are mainly associated with higher labour and non-labour costs to reflect the retirement of the CTGS and costs previously shared between the four generation assets now allocated to the three remaining generation assets.

The 2022 to 2025 forecasts for fuel costs are based on the generation of 1.2 GWh in each of 2022, 2023 and 2024 and 2.0 GWh in 2025, which includes testing and required generation to meet load requirements. The forecast fuel price is based on the US Energy Information Administration Forecast of future projected fuel prices at the time Maritime Electric's forecast was prepared.

The labour and non-labour forecasts for 2023 to 2025 reflect inflationary increases offset by labour savings in 2023 and 2024 as employees are temporarily reassigned to CTGS decommissioning activities. The 2025 labour forecast reflects employees returning to CT1 and CT2 maintenance and production duties.

C.1.5 Energy Control Centre

This category provides for the 24/7 operation of the Company's Energy Control Centre, which is responsible for scheduling hourly energy purchases, monitoring and operating the Company's transmission and distribution system, managing the submarine cable loading and dispatching on-Island generation, amongst other duties.

Table C-14 provides the historical costs related to the Energy Control Centre for 2019 to 2021.

TABLE C-14 Energy Control Centre Historical Results ($000, expect %)									
	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Labour	1,043	936	(107)	1,011	924	(87)	1,086	976	(110)
Contractors	5	1	(4)	-	-	-	-	2	2
Non-labour	12	15	3	37	25	(12)	72	22	(50)
Total	**1,060**	**952**	**(108)**	**1,048**	**949**	**(99)**	**1,158**	**1,000**	**(158)**
Variance %			*(10)%*			*(9)%*			*(14)%*

The 2019, 2020 and 2021 costs did not vary materially from forecast. Nonetheless, labour costs were consistently lower than forecast as internal resources were temporarily reassigned to other departments to respond to work loads.

Table C-15 provides the forecast costs related to the Energy Control Centre for 2022 to 2025.

TABLE C-15 Energy Control Centre 2022 and GRA Forecast ($000, except %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	1,051	75	(35)	1,036	(15)	1,081	45	1,134	53
Contractors	-	(2)	-	-	-	-	-	-	-
Non-labour	76	54	4	70	(6)	73	3	72	(1)
Total	**1,127**	**127**	**(31)**	**1,106**	**(21)**	**1,154**	**48**	**1,206**	**52**
Variance %		*13%*	*(3)%*		*(2)%*		*4%*		*5%*

The 2022 forecast did not vary materially from the prior year actual or forecast.

The 2023 to 2025 forecasts are based on historical actuals adjusted for inflation.

C.1.6 Interconnection Costs

The interconnection costs includes: (i) the interconnection lease payments for the two newer underwater cables; (ii) NB Power's OATT Schedule 9 – Direct Assignment charges for the transmission lines from Memramcook to Cape Tormentine; (iii) the Company's required contributions to the PEIEC's cable contingency fund; and (iv) maintenance costs (i.e., labour, contractors and non-labour) associated with Murray Corner and Memramcook switching stations in New Brunswick.

Table C-16 provides the historical interconnection costs for 2019 to 2021.

TABLE C-16
Interconnection Costs
Historical Results ($000, except %)

	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Lease Payments	3,228	3,222	(6)	3,239	3,246	7	3,239	3,218	(21)
Schedule 9 Charges	1,160	1,194	34	1,161	1,135	(26)	1,161	1,129	(32)
Cable Contingency Fund	375	-	(375)	375	-	(375)	375	375	-
Labour	42	27	(15)	21	22	1	27	25	(2)
Contractors	-	-	-	6	27	21	-	18	18
Non-labour	182	145	(37)	171	172	1	194	221	27
Total	**4,987**	**4,588**	**(399)**	**4,973**	**4,602**	**(371)**	**4,996**	**4,986**	**(10)**
Variance %			*(8)%*			*(7)%*			*-%*

The 2019, 2020 and 2021 costs did not vary materially from forecast, with the exception of the cable contingency fund contributions. The forecasts assumed the cable contingency fund contributions would have been approved in the Company's revenue requirement effective in 2019, rather than as a rate rider. However, rate adjustments were not approved until January 1, 2021. Therefore, in 2019 and 2020 the cable contingency fund contributions continued to be collected from customers via a rate rider.

Table C-17 provides the forecast interconnection costs for 2022 to 2025.

TABLE C-17 Interconnection Costs 2022 and GRA Forecast ($000, except %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Lease Payments	3,050	(168)	(189)	2,882	(168)	2,882	-	2,882	-
Schedule 9 Charges	1,113	(16)	(48)	1,098	(15)	1,098	-	1,109	11
Cable Contingency Fund	375	-	-	375	-	375	-	375	-
Labour	30	5	3	31	1	53	22	59	6
Contractors	-	(18)	-	-	-	-	-	-	-
Non-labour	230	9	36	219	(11)	223	4	228	5
Total	**4,798**	**(188)**	**(198)**	**4,605**	**(193)**	**4,631**	**26**	**4,653**	**22**
Variance %		*(4)%*	*(4)%*		*(4)%*		*1%*		*-%*

The 2022 variance compared to the prior year actual and forecast is driven by a reduction to the interconnection lease payments, which reflects new lease terms effective July 1, 2022 that are currently being negotiated.

The 2023 to 2025 forecasts are based on historical actuals along with new lease terms effective July 1, 2022.

C.1.7 Other NB Power Charges

This category provides for the use of NB Power's transmission assets, including: (i) operating and maintenance charges for the use of NB Power's transmission lines; (ii) operating and maintenance charges for the use of NB Power's Memramcook terminal station; (iii) a circuit breaker rental fee; (iv) fees to utilize the Open Access Technology Inc. ("OATI") e-tagging system for entering energy requirements; and (v) the cost to purchase and secure transmission capacity in New Brunswick associated with the 30 MW International Power Line.

Table C-18 provides the historical other NB Power charges for 2019 to 2021.

TABLE C-18 Other NB Power Charges Historical Results ($000, except %)											
2019				**2020**				**2021**			
Forecast	**Actual**	**Variance**		**Forecast**	**Actual**	**Variance**		**Forecast**	**Actual**	**Variance**	
1,475	1,495	20	*1%*	1,487	1,500	13	*1%*	1,545	1,504	(41)	*(3)%*

The 2019, 2020 and 2021 costs did not vary materially from forecast.

Table C-19 provides the forecast other NB Power charges for 2022 to 2025.

TABLE C-19 Other NB Power Charges 2022 and GRA Forecast ($000, except %)													
2022					**2023**			**2024**			**2025**		
Forecast	**Variance vs Prior Year Actual**		**Variance vs Prior Year Forecast**		**Forecast**	**Variance vs Prior Year Forecast**		**Forecast**	**Variance vs Prior Year Forecast**		**Forecast**	**Variance vs Prior Year Forecast**	
1,629	125	*8%*	84	*5%*	1,753	124	*8%*	1,761	8	*-%*	1,793	32	*2%*

The 2022 costs are not forecast to vary materially from the prior year actual or forecast. Nonetheless, the 2022 forecast reflects a proposed increase to the International Power Line transmission capacity costs, under the NB Power OATT, effective July 1, 2022.

The 2023 to 2025 forecasts are based on historical actuals adjusted for inflation and expected changes to the NB Power OATT.

C.1.8 Provincial Debt Repayment Costs

This category provides for the annual payment of costs recoverable from customers on behalf of the Province. The debt repayment costs reflect the PEIEC's expected financing arrangements for those deferred energy costs assumed by the Province under the PEI Energy Accord. Under Order UE19-08, these costs are currently collected as a separate rate rider and has not been part of the Company's revenue requirement. In accordance with Order UE20-06, the Company proposes that these costs be included in the Company's revenue requirement beginning on March 1, 2023.

As such, the costs will no longer be collected as a separate rate rider but will be included in the basic energy charge.

Table C-20 provides the historical debt repayment costs for 2019 to 2021.

TABLE C-20 Provincial Debt Repayment Costs Historical Results ($000, except %)											
2019				**2020**				**2021**			
Forecast	**Actual**	**Variance**		**Forecast**	**Actual**	**Variance**		**Forecast**	**Actual**	**Variance**	
1,913	-	(1,913)	*(100)%*	-	-	-	*-%*	-	-	-	*-%*

The 2019 forecast reflects the 2019 GRA proposal that the debt repayment costs be recovered as part of energy supply costs through the Energy Cost Adjustment Mechanism (“ECAM”). The Island Regulatory and Appeals Commission (“IRAC” or the “Commission”) denied this proposal in Order UE19-08. In the corresponding resubmission for the 2020 and 2021 forecasts, the Company reflected the collection of the debt repayment costs to continue as a rate rider, which is discussed in Sections 5.1.1 and 5.3.6 of this Application.

Table C-21 provides the forecast debt repayment costs for 2022 to 2025.

TABLE C-21 Provincial Debt Repayment Costs 2022 and GRA Forecast ($000, except %)													
2022					**2023**			**2024**			**2025**		
Forecast	**Variance vs Prior Year Actual**		**Variance vs Prior Year Forecast**		**Forecast**	**Variance vs Prior Year Forecast**		**Forecast**	**Variance vs Prior Year Forecast**		**Forecast**	**Variance vs Prior Year Forecast**	
-	-	*-%*	-	*-%*	4,103	4,103	*100%*	5,411	1,308	*32%*	5,457	46	*1%*

The currently approved rate rider, of $0.0036 per kWh, will remain in effect until new rates are approved, and this Application seeks approval of new rates effective March 1, 2023. In accordance with Order UE20-06, this Application proposes the debt repayment costs be included in the revenue requirement, rather than a rate rider. Therefore, the 2023 forecast reflects debt repayment costs from March 1 to December 31, and the 2024 and 2025 forecast reflects a full year of debt repayment costs. The debt repayment costs are based on the April 2021 Debt Collection Agreement with the PEIEC.

C.1.9 Other Energy Supply Costs

This category provides for the insurance, property tax and employee training related to the energy supply function.

Table C-22 provides the costs for 2019 to 2021.

TABLE C-22 Other Energy Supply Costs Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Insurance	613	587	(26)	665	664	(1)	651	780	129
Property Tax	230	224	(6)	227	228	1	243	235	(8)
Employee Training	35	17	(18)	27	13	(14)	60	5	(55)
Total	**878**	**828**	**(50)**	**919**	**905**	**(14)**	**954**	**1,020**	**66**
Variance %			*(6)%*			*(2)%*			*7%*

The 2019 to 2021 costs did not vary materially from forecast.

Table C-23 provides the forecast costs for 2022 to 2025.

TABLE C-23 Other Energy Supply Costs 2022 and GRA Forecast ($000, expect %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Insurance	971	191	320	1,057	86	1,104	47	1,154	50
Property Tax	237	2	(6)	243	6	249	6	255	6
Employee Training	20	15	(40)	30	10	31	1	32	1
Total	**1,228**	**208**	**274**	**1,330**	**102**	**1,384**	**54**	**1,441**	**57**
Variance %		*20%*	*29%*		*8%*		*4%*		*4%*

With respect to insurance, the 2022 forecast reflects an annual premium increase effective July 2021. Annual premium increases are expected to be above inflation over the 2022 to 2025 period at approximately 5 per cent.

With respect to property taxes, the forecast is based on inflationary increases in the market value assessments of the physical properties associated with the Company's generation facilities.

With respect to employee training, the 2022 to 2025 forecasts reflect a return to pre-pandemic training levels adjusted for inflation.

C.2 Transmission Expense

Table C-24 outlines the transmission expenses for 2019 to 2025.

TABLE C-24 Transmission Expense ($000)							
Description	**2019 Actual**	**2020 Actual**	**2021 Actual**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
Substations	62	67	69	80	82	89	91
Rights of Way	143	230	544	397	473	551	627
Line Maintenance	290	245	260	322	326	333	354
Line Control Devices	47	55	61	79	81	83	85
Engineering	129	142	143	187	209	223	229
Total	671	739	1,077	1,065	1,171	1,279	1,386

A discussion of each category along with variance analyses is provided in the remainder of this section.

C.2.1 Substations

This category provides for the maintenance and inspection of the Company's transmission substations. It includes labour and related transportation costs as well as materials to maintain the transmission switches, insulators, bus connectors and transformers.

Table C-25 provides a breakdown of historical substation costs.

TABLE C-25 Substations Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	53	42	(11)	49	55	6	66	54	(12)
Contractors	10	16	6	6	11	5	11	15	4
Non-labour	-	4	4	6	1	(5)	-	-	-
Total	**63**	**62**	**(1)**	**61**	**67**	**6**	**77**	**69**	**(8)**
Variance %			*(2)%*			*10%*			*(10)%*

On an overall basis, substations costs for 2019, 2020 and 2021 did not vary materially from forecast. Due to the nature of the work involved and the availability of internal resources to perform the work, certain repairs were conducted by contractors instead of internal resources.

Table C-26 provides a breakdown of forecast substation costs for 2022 to 2025.

TABLE C-26
Substations
2022 and GRA Forecast ($000, expect %)

	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	69	15	3	71	2	78	7	80	2
Contractors	11	(4)	-	11	-	11	-	11	-
Total	**80**	**11**	**3**	**82**	**2**	**89**	**7**	**91**	**2**
Variance %		*16%*	*4%*		*3%*		*9%*		*2%*

The 2022 variance over the prior year actual was a direct result of increasing customer load growth. To respond to load growth, the number of transmission substations have increased by 25 per cent over the last 10 years, from 24 substations in 2011 to 30 in 2021. As a result, the 2022 labour variance, compared to the prior year actual, and the 2024 labour variance reflect a higher allocation of internal resources to complete the expected increased volume of repairs and maintenance.

C.2.2 Rights of Way

This category provides for the maintenance and inspection of transmission rights of way, also referred to as vegetation management, for the Company's approximately 800 kilometres ("km") of transmission lines. The majority of these costs are for third-party contract labour and internal supervisory labour including related equipment and transportation costs.

Table C-27 provides a breakdown of historical costs associated with transmission rights of way.

TABLE C-27 Rights of Way Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	16	17	1	10	12	2	17	6	(11)
Contractors	361	126	(235)	222	218	(4)	383	538	155
Total	**377**	**143**	**(234)**	**232**	**230**	**(2)**	**400**	**544**	**144**
Variance %			*(62)%*			*(1)%*			*36%*

The 2019 variance was due to a decrease in contractor costs, which was primarily a result of contractor crews being reassigned to distribution rights of way for vegetation clean-up associated with post-tropical storm Dorian.[11]

The 2020 costs did not vary materially from forecast.

The 2021 variance was due to an increase in contractors hired to complete additional vegetation management. As discussed in Section 5.1.2 of this Application and Appendix E, the Company has identified an immediate need for enhanced vegetation management activities. In 2021, operating and finance cost savings were realized and optimally redirected to vegetation management to improve overall reliability for customers.

Table C-28 provides a breakdown of forecast associated with transmission rights of way for 2022 to 2025.

[11] Between September 7, 2019, when post-tropical storm Dorian made landfall on PEI, and September 15, 2019, when power was restored to all customers, costs incurred were captured in a deferral account. Repairs and clean-up related to the storm was required beyond that period and such costs were expensed.

TABLE C-28 Rights of Way 2022 and GRA Forecast ($000, expect %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Labour	40	34	23	41	1	42	1	43	1
Contractors	357	(181)	(26)	432	75	509	77	584	75
Total	**397**	**(147)**	**(3)**	**473**	**76**	**551**	**78**	**627**	**76**
Variance %		*(27)%*	*(1)%*		*19%*		*16%*		*14%*

The 2022 forecast is lower than the prior year actual due to higher contractor costs incurred in 2021, as discussed above. The 2022 forecast is materially consistent with the prior year forecast.

The 2023 to 2025 forecast for contractor costs reflects the Company's enhanced vegetation management program. Evidence to support the enhanced program is provided in Appendix E.

C.2.3 Line Maintenance

This category provides for the inspection and maintenance of the transmission assets. These costs are driven by preventative maintenance and responding to outages, including those caused by weather events. Activities include repairing wires, connectors, and insulators, straightening poles and retightening guy wires and other hardware.

Table C-29 provides a breakdown of historical line maintenance costs.

TABLE C-29 Line Maintenance Historical Results ($000, expect %)									
	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Labour	259	236	(23)	250	247	(3)	283	237	(46)
Contractors	10	20	10	-	12	12	11	-	(11)
Non-labour	31	34	3	2	(14)	(16)	24	23	(1)
Total	**300**	**290**	**(10)**	**252**	**245**	**(7)**	**318**	**260**	**(58)**
Variance %			***(3)%***			***(3)%***			***(18)%***

The 2019 and 2020 costs did not materially vary from forecast. The 2021 variance was primarily due to fewer-than-expected weather-related outages.

Table C-30 provides a breakdown of forecast line maintenance costs for 2022 to 2025.

TABLE C-30 Line Maintenance 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	289	52	6	292	3	298	6	318	20
Contractors	10	10	(1)	10	-	11	1	11	-
Non-labour	23	-	(1)	24	1	24	-	25	1
Total	**322**	**62**	**4**	**326**	**4**	**333**	**7**	**354**	**21**
Variance %		*24%*	*1%*		*1%*		*2%*		*6%*

The 2022 variance compared to the prior year actual is primarily due to higher labour costs, which reflects a proportionate allocation of a new Standards and Training Coordinator as well as additional power line technician apprentices hired to replace expected retirements in the near term.

The forecasts for 2023 to 2025 are based on a typical level of weather-related outages and historical actuals adjusted for inflation. The 2024 and 2025 labour variances reflects additional power line technician apprentices to be hired in the fall of 2024 in anticipation of retirements post 2025.

C.2.4 Line Control Devices

This category provides for the inspection and preventative maintenance of the transmission line control devices such as circuit breakers, switches, circuit switches and capacitors located in the Company's substations. The activities include inspection, replacing broken bushings, repainting and repairing control modules.

Table C-31 provides a breakdown of historical costs associated with line control devices.

TABLE C-31
Line Control Devices
Historical Results ($000, expect %)

	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Labour	61	47	(14)	56	55	(1)	76	61	(15)
Total	**61**	**47**	**(14)**	**56**	**55**	**(1)**	**76**	**61**	**(15)**
Variance %			*(23)%*			*(2)%*			*(20)%*

The 2019 and 2021 variances were due primarily to lower-than-expected weather-related outages affecting transmission line control devices. The 2020 costs did not vary materially from forecast.

Table C-32 provides a breakdown of forecast costs associated with line control devices for 2022 to 2025.

TABLE C-32 Line Control Devices 2022 and GRA Forecast ($000, expect %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Labour	79	18	3	81	2	83	2	85	2
Total	**79**	**18**	**3**	**81**	**2**	**83**	**2**	**85**	**2**
Variance %		*30%*	*4%*		*3%*		*2%*		*2%*

The 2022 variance compared to the prior year actual reflects an expected return to a normal level of weather-related repairs along with a slightly higher allocation of internal labour to operating versus capital activities. The 2022 forecast did not vary materially from the prior year forecast.

The 2023 to 2025 forecasts historical actuals adjusted for inflation and reflect a normal level of weather-related repairs.

C.2.5 Engineering

This category provides for the engineering support and analysis required to design, operate and maintain the transmission system. Activities include power flow analysis, equipment monitoring, and engineering analysis to ensure optimal system operation.

Table C-33 provides a breakdown of historical engineering costs.

TABLE C-33 Engineering Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	143	129	(14)	165	142	(23)	154	143	(11)
Total	**143**	**129**	**(14)**	**165**	**142**	**(23)**	**154**	**143**	**(11)**
Variance %			*(10)%*			*(14)%*			*(7)%*

The 2019 and 2020 variances were primarily due to the replacement of a senior engineer, who retired mid-2019, with an entry level engineer. The 2021 costs did not vary materially from forecast.

Table C-34 provides a breakdown of forecast engineering costs for 2022 to 2025.

TABLE C-34 Engineering 2022 and GRA Forecast ($000, expect %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Labour	187	44	33	209	22	223	14	229	6
Total	**187**	**44**	**33**	**209**	**22**	**223**	**14**	**229**	**6**
Variance %		*31%*	*21%*		*12%*		*7%*		*3%*

The 2022 variances compared to the prior year actual and prior year forecast reflect a proportionate allocation of a new Standards and Training Coordinator and a proportionate allocation of a Technical Services Supervisor, a position which had been vacant since 2019.[12]

[12] The cost of the Standards and Training Coordinator is principally shared between transmission and distribution engineering and transmission line maintenance. The cost of the Technical Services Supervisor is principally shared between transmission and distribution engineering, supervisory SCADA, and capital activities.

The 2023 and 2024 variances reflect a proportionate allocation of two additional junior engineers in mid-2023, which are required to support the capital program and operating requirements.[13] The remaining increases in 2023 to 2025 reflect historical actuals adjusted for inflation.

C.3 Open Access Transmission Tariff

This category provides for the OATT tariff as well as the administration and operation of the OATT (i.e., operations). Table C-35 outlines the OATT expenses for the period 2019 to 2025.

TABLE C-35
OATT Expenses ($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Network Service	7,545	7,809	7,984	9,317	10,577	10,752	10,938
Schedule 1	237	245	250	261	267	271	275
Schedule 2	316	327	335	271	195	198	202
Schedule 3C	13	16	14	-	-	-	-
Schedule 4	104	138	(88)	-	-	-	-
Schedule 9	67	67	67	67	66	66	66
Operations	238	218	226	343	316	324	332
Total	**8,520**	**8,820**	**8,788**	**10,259**	**11,421**	**11,611**	**11,813**

[13] The cost of the two engineers is principally shared between transmission and distribution engineering, and capital activities.

Table C-36 provides a breakdown of historical OATT costs.

TABLE C-36 OATT Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Network	7,200	7,545	345	7,853	7,809	(44)	8,261	7,984	(277)
Schedule 1	211	237	26	205	245	40	210	250	40
Schedule 2	341	316	(25)	331	327	(4)	340	335	(5)
Schedule 3C[14]	-	13	13	-	16	16	-	14	14
Schedule 4[15]	-	104	104	-	138	138	-	(88)	(88)
Schedule 9	75	67	(8)	75	67	(8)	75	67	(8)
Subtotal	**7,827**	**8,282**	**455**	**8,464**	**8,602**	**138**	**8,886**	**8,562**	**(324)**
Operations – Labour	248	227	(21)	214	214	-	254	223	(31)
Operations – Non-labour	62	11	(51)	42	4	(38)	75	3	(72)
Total	**8,137**	**8,520**	**383**	**8,720**	**8,820**	**100**	**9,215**	**8,788**	**(427)**
Variance %			*5%*			*1%*			*(5)%*

The 2019 variance reflects a forecast that was prepared using interim OATT rates compared to actuals based on higher OATT rates that were approved effective August 1, 2018. The 2019 operations labour variance reflects lower-than-planned Energy Control Centre operator costs and the operations non-labour variance was primarily due to lower OATI maintenance fees.[16]

The 2020 costs did not vary materially from forecast.

[14] Schedule 3C, Regulation and Load Following is a service charge from the New Brunswick System Operator that flow through to the transmission customer with no markup and has a net zero impact to Maritime Electric; hence, no amounts are forecast.

[15] Schedule 4, Energy Imbalance Service, is the difference between scheduled and actual hourly transmission system service. As these charges flow directly through to the transmission customer with no markup and has a net zero impact to Maritime Electric, no amounts are forecast.

[16] The Company licenses its transmission scheduling software from the Open Access Technology International Inc. ("OATI"). Prior to 2019, the Company was paying approximately $38 thousand annually for scheduling services software. In April 2019, the Company reduced the services subscribed and annual costs were reduced to approximately $10 thousand.

The 2021 variance was primarily due to lower network charges, which reflect lower-than-planned energy sales requiring less transmission of energy, and operation costs. The operations labour variance reflects lower-than-planned Energy Control Centre operator costs and the operations non-labour variance was primarily due to lower OATI maintenance fees.

Table C-37 provides a breakdown of forecast OATT costs for 2022 to 2025.

TABLE C-37
OATT
2022 and GRA Forecast ($000, expect %)

	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Network	9,317	1,333	1,056	10,577	1,260	10,752	175	10,938	186
Schedule 1	261	11	51	267	6	271	4	275	4
Schedule 2	271	(64)	(69)	195	(76)	198	3	202	4
Schedule 3C	-	(14)	-	-	-	-	-	-	-
Schedule 4	-	88	-	-	-	-	-	-	-
Schedule 9	67	-	(8)	66	(1)	66	-	66	-
Subtotal	**9,916**	**1,354**	**1,030**	**11,105**	**1,189**	**11,287**	**182**	**11,481**	**194**
Operations - Labour	295	72	41	303	8	310	7	318	8
Operations – Non-labour	48	45	(27)	13	(35)	14	1	14	-
Total	**10,259**	**1,471**	**1,044**	**11,421**	**1,162**	**11,611**	**190**	**11,813**	**202**
Variance %		*17%*	*11%*		*11%*		*2%*		*2%*

The 2022 variances compared to both the prior year actual and forecast are primarily due to higher network charges, which reflects an assumption that new OATT charges will be effective July 30, 2022[17] and an expected increase in energy transmission to meet customer sales. The 2023 variance is primarily due to higher network charges, reflecting the rate increase effective July 30, 2022.

[17] Commission Docket UE20945.

The 2022 operations labour forecast includes the addition of an OATT administrator along with inflationary increases to existing Energy Control Centre operator costs.[18] The 2022 operations non-labour forecast reflects a one-time increase of $40 thousand for IRAC hearing costs. The operations forecast for 2023 to 2025 reflects adjustments for inflation.

C.4 Distribution Expenses

Table C-38 outlines the distribution expenses for 2019 to 2025.

TABLE C-38
Distribution Expenses ($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
Substations	101	120	109	122	126	129	135
Rights of way	1,596	1,414	2,766	1,831	2,144	2,773	3,362
Line Maintenance	1,805	2,145	1,569	2,059	2,094	2,241	2,242
Line Control Devices	56	37	41	55	56	57	59
Transformers	701	638	659	637	641	655	694
Meters	173	163	165	190	194	199	204
Communication Systems	160	211	236	251	258	264	271
Supervisory SCADA	89	93	101	121	124	128	131
Engineering	350	366	385	442	472	497	509
Total	**5,031**	**5,187**	**6,031**	**5,708**	**6,109**	**6,943**	**7,607**

A discussion of each category along with variance analyses is provided in the remainder of this section.

C.4.1 Substations

This category provides for the inspection and maintenance of the Company's distribution substations. It includes labour, material and transportation to maintain the switches, insulators, bus connectors, substation fence and ground grid and vegetation management inside the substation fence.

[18] The 2022 forecast reflects 75 per cent of the labour cost of a new employee to serve the role of OATT administrator, with the other 25 per cent allocated to the Energy Control Centre.

Table C-39 provides a breakdown of historical costs associated with substations.

TABLE C-39
Substations
Historical Results ($000, expect %)

	2019			2020			2021		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	52	37	(15)	30	28	(2)	42	34	(8)
Contractors	2	1	(1)	65	61	(4)	3	43	40
Non-labour	56	63	7	37	31	(6)	58	32	(26)
Total	**110**	**101**	**(9)**	**132**	**120**	**(12)**	**103**	**109**	**6**
Variance %			*(8)%*			*(9)%*			*6%*

The 2019 costs did not vary materially from forecast. The labour decrease from forecast was primarily due to the reassignment of internal resources to repair transformer damage sustained from post-tropical storm Dorian.

In 2020 costs did not vary materially from forecast.

The 2021 costs did not vary materially from forecast. The 2021 variances in contractors and non-labour costs materially offset each other as costs were originally forecast as non-labour. As well, substation maintenance originally expected to be performed by internal labour was partially contracted out due to internal resources being needed to work on capital projects.

Table C-40 provides a breakdown of forecast costs associated with substations for 2022 to 2025.

TABLE C-40 Substations 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	43	9	1	40	(3)	80	40	84	4
Contractors	55	12	52	62	7	24	(38)	25	1
Non-labour	24	(8)	(34)	24	-	25	1	26	1
Total	**122**	**13**	**19**	**126**	**4**	**129**	**3**	**135**	**6**
Variance %		*12%*	*18%*		*3%*		*2%*		*5%*

The 2022 forecast does not vary materially from the prior year actual or forecast. The 2022 forecast costs have moved to contractor from the labour and non-labour categories to reflect the coding of actual charges incurred in 2021.

The forecasts for 2023 to 2025 are based on historical actuals adjusted for inflation. In 2024 a shift to internal labour from contractors is forecast to reflect internal resources returning to substation maintenance upon the completion of the CTGS decommissioning project; therefore, the forecast for contractors has been reduced accordingly.

C.4.2 Rights of way

This category provides for the inspection and maintenance of the rights of way, also referred to as vegetation management, for the Company's approximately 5,800 km of distribution lines. The majority of these costs are for third-party contract labour and internal supervisory labour including related equipment and transportation costs.

Table C-41 provides a breakdown of historical costs associated with distribution rights of way.

TABLE C-41 Rights of Way Historical Results ($000, expect %)									
	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Labour	109	126	17	101	94	(7)	112	267	155
Contractors	1,219	1,470	251	1,123	1,312	189	1,307	2,498	1,191
Non-labour	15	-	(15)	16	8	(8)	17	1	(16)
Total	**1,343**	**1,596**	**253**	**1,240**	**1,414**	**174**	**1,436**	**2,766**	**1,330**
Variance %			*19%*			*14%*			*93%*

The 2019 labour and contractor variances were due primarily to vegetation clean-up associated with post-tropical storm Dorian.

The 2020 contractor variance was due to vegetation clearing for the connection of the Y-109 tap to Clyde River substation. The vegetation clearing was in an environmentally sensitive area which had not been known when the forecast was developed. Labour and non-labour costs did not vary materially from forecast.

The 2021 labour and contractor variances were due to increased vegetation management. As discussed in Section 5.1.2 of this Application and Appendix E, the Company has identified an immediate need for enhanced vegetation management activities. In 2021, operating and finance cost savings were realized and optimally redirected to vegetation management to improve overall reliability for customers.

Table C-42 is a breakdown of forecast contractor costs associated with distribution rights of way for 2022 to 2025.

TABLE C-42 Rights of Way 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	135	(132)	23	137	2	140	3	149	9
Contractors	1,689	(809)	382	2,000	311	2,626	626	3,206	580
Non-labour	7	6	(10)	7	-	7	-	7	-
Total	**1,831**	**(935)**	**395**	**2,144**	**313**	**2,773**	**629**	**3,362**	**589**
Variance %		*(34)%*	*28%*		*17%*		*29%*		*21%*

The 2022 forecast is lower than the prior year actual and higher than the prior year forecast. The decrease compared to the prior year actual is due to higher vegetation management costs incurred in 2021, as discussed above. The 2022 labour forecast is higher than the prior year forecast reflecting a proportionate allocation of the addition of a new vegetation management coordinator to plan and supervise the Company's vegetation management plan, for both transmission and distribution rights of way. The 2022 contractor forecast is higher than the prior year forecast reflecting the fact that the 2021 forecast did not accurately reflect the required volume of vegetation management needed.

The 2023 to 2025 forecast for contractor costs reflects the Company's enhanced vegetation management program. Evidence to support the program is provided in Appendix E.

C.4.3 Line Maintenance

This category provides for the inspection and maintenance of distribution assets. Expenditures are driven by preventative maintenance, customer requests, and responding to weather-related outages. Activities include repairing wires and connectors during no power calls, replacing fuses, straightening poles, retightening guy wires, repairs to underground services and streetlight maintenance. This account also includes expenditures for small tool and equipment purchases, flame resistant safety clothing, and tool and equipment testing.

Table C-43 provides a breakdown of historical line maintenance costs.

TABLE C-43 Line Maintenance Historical Results ($000, expect %)									
	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Labour	1,018	1,027	9	993	1,023	30	1,122	1,014	(108)
Contractors	258	295	37	260	258	(2)	273	-	(273)
Non-labour	593	483	(110)	662	864	202	631	555	(76)
Total	**1,869**	**1,805**	**(64)**	**1,915**	**2,145**	**230**	**2,026**	**1,569**	**(457)**
Variance %			*(3)%*			*12%*			*(23)%*

The 2019 variance was driven by a decrease in non-labour costs, partially offset by an increase in contractor costs. The 2019 non-labour variance was primarily due to lower-than-expected costs for materials and supplies and the 2019 contractor variance was primarily due to costs associated with post-tropical storm Dorian.

The 2020 variance was driven by an increase in non-labour costs, which included approximately $100 thousand to repair accidental damage to third-party communications fibre that occurred while the Company was performing work on our own assets. The remaining variance was primarily due to the cost of pandemic-related safety measures.[19]

The 2021 labour variance was primarily due to fewer-than-expected weather-related outages resulting in lower over-time and double-time. In addition, an apprenticeship bootcamp and subsequent hiring of power line technician apprentices, which was originally planned for early in 2021, was postponed until the fourth quarter of 2021 resulting in lower-than-planned labour costs. The 2021 contractor and non-labour variances were primarily due to fewer-than-expected weather-related outages.

Table C-44 provides a breakdown of forecast line maintenance costs for 2022 to 2025.

[19] Pandemic-related safety measures included vehicle rentals to maintain physical distancing while travelling to and from work sites, additional cleaning measures, purchase of masks, and portable washroom rentals.

TABLE C-44 Line Maintenance 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	1,132	118	10	1,143	11	1,161	18	1,242	81
Contractors	279	279	6	286	7	293	7	300	7
Non-labour	648	93	17	665	17	787	122	700	(87)
Total	**2,059**	**490**	**33**	**2,094**	**35**	**2,241**	**147**	**2,242**	**1**
Variance %		*31%*	*2%*		*2%*		*7%*		*-%*

The 2022 forecast is higher than the prior year actual as weather-related outages were abnormally low in 2021. The 2022 forecast did not vary materially from the prior year forecast.

The 2023 to 2025 forecasts are based on historical actuals adjusted for inflation and adjusted to reflect a typical level of weather-related outages. In 2024, non-labour costs include a power line technician bootcamp to hire apprentices in the fall of 2024 in anticipation of retirements post 2025.

C.4.4 Line Control Devices

This category provides for the inspection and maintenance of distribution line control devices such as capacitors, voltage regulators and reclosers including inspection, replacing broken bushings, repainting and repairing control modules.

Table C-45 provides a breakdown of historical costs associated with line control devices.

TABLE C-45 Line Control Devices Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	46	33	(13)	33	25	(8)	54	28	(26)
Non-labour	16	23	7	14	12	(2)	16	13	(3)
Total	**62**	**56**	**(6)**	**47**	**37**	**(10)**	**70**	**41**	**(29)**
Variance %			*(10)%*			*(21)%*			*(41)%*

The 2019 and 2020 costs did not vary materially from forecast.

The 2021 variance was driven by high labour costs which reflects the mid-year replacement of an employee that was reassigned in 2019.

Table C-46 provides a breakdown of forecast costs associated with line control devices for 2022 to 2025.

TABLE C-46 Line Control Devices 2022 and GRA Forecast ($000, expect %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Labour	40	12	(14)	41	1	41	-	43	2
Non-labour	15	2	(1)	15	-	16	1	16	-
Total	**55**	**14**	**(15)**	**56**	**1**	**57**	**1**	**59**	**2**
Variance %		*34%*	*(21)%*		*2%*		*2%*		*4%*

The 2022 forecast did not vary materially from the prior year actual or forecast.

The 2023 to 2025 forecast costs are based on historical actuals adjusted for inflation.

C.4.5 Transformers

This category provides for the inspection and maintenance of distribution transformers, which includes both pole-mount and pad-mount units. The activities include inspection, testing, replacing broken bushings, repainting, and oil spill cleanup.

Table C-47 provides a breakdown of historical transformer costs.

TABLE C-47
Transformers
Historical Results ($000, expect %)

	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	436	616	180	516	548	32	474	559	85
Contractors	-	5	5	1	5	4	-	-	-
Non-labour	67	80	13	75	85	10	71	100	29
Total	**503**	**701**	**198**	**592**	**638**	**46**	**545**	**659**	**114**
Variance %			*39%*			*8%*			*21%*

The 2019, 2020 and 2021 variances were driven by increases in labour costs compared to forecast, which was primarily due to the reassignment of resources to assist with increased transformer maintenance activity.[20] The non-labour variances were primarily due to higher-than-expected cost and volume of materials and supplies required for the increase maintenance workload.

Table C-48 provides a breakdown of forecast transformer costs for 2022 to 2025.

[20] Labour resources were initially reassigned in 2019 to assist with increased transformer maintenance related to post-tropical storm Dorian and remained assigned to transformer maintenance even after the increased workload related to Dorian was completed. While not contemplated when the forecasts for 2020 and 2021 were prepared, the reassignment coincided with a sustained increased workload in the transformer maintenance shop and a decreased workload at the CTGS.

TABLE C-48 Transformers 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	537	(22)	63	538	1	549	11	585	36
Non-labour	100	-	29	103	3	106	3	109	3
Total	**637**	**(22)**	**92**	**641**	**4**	**655**	**14**	**694**	**39**
Variance %		*(3)%*	*17%*		*1%*		*2%*		*6%*

The 2022 variance compared to the prior year actual reflects an employee temporarily reassigned to the CTGS in 2022 to assist with scheduled decommissioning activities and returning to the transformer maintenance shop mid-2024.

The 2022 labour variance compared to the prior year forecast reflects the fact that the 2021 forecast did not contemplate the higher level of internal resources required. The 2022 non-labour variance reflects recent price escalations. Global supply chain issues have resulted in a significant increase in the price of various materials, particularly related to transformers.

The 2023 to 2025 forecast reflects historical actuals adjusted for inflation and the reassignment of internal resources to deal with increased transformer workload.

C.4.6 Meters

This category provides for the inspection, testing and maintenance of approximately 87,000 revenue meters. Maintenance is driven by compliance with Measurement Canada rules and regulations and the number of units requiring maintenance changes year over year. Meter testing is performed by a third party, and this testing determines if the sample set of meters meet industry standards or require replacement.

Table C-49 provides a breakdown of historical meter costs.

TABLE C-49 Meters Historical Results ($000, expect %)									
	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Labour	99	92	(7)	85	82	(3)	106	97	(9)
Non-labour	81	81	-	72	81	9	84	68	(16)
Total	**180**	**173**	**(7)**	**157**	**163**	**6**	**190**	**165**	**(25)**
Variance %			*(4)%*			*4%*			*(13)%*

In 2019, 2020 and 2021 meter costs did not vary materially from forecast.

Table C-50 provides a breakdown of forecast meter costs for 2022 to 2025.

TABLE C-50 Meters 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	106	9	-	108	2	111	3	113	2
Non-labour	84	16	-	86	2	88	2	91	3
Total	**190**	**25**	**-**	**194**	**4**	**199**	**5**	**204**	**5**
Variance %		*15%*	*-%*		*2%*		*3%*		*3%*

The 2022 forecast compared to the prior year actual reflects the fact that the 2022 forecast was consistent with the 2021 forecast.

The 2023 to 2025 forecasts are based on historical actuals adjusted for inflation.

C.4.7 Communications Systems

The category provides for the operation and maintenance of communication hardware, such as radios, routers, fibre optic cables and tele protection equipment which is used for the Company's protection and control facilities and communications systems.

Table C-51 provides a breakdown of historical communications systems costs.

TABLE C-51 Communications Systems Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	124	95	(29)	109	111	2	155	122	(33)
Contractors	3	-	(3)	-	-	-	3	-	(3)
Non-labour	109	65	(44)	114	100	(14)	115	114	(1)
Total	**236**	**160**	**(76)**	**223**	**211**	**(12)**	**273**	**236**	**(37)**
Variance %			*(32)%*			*(5)%*			*(14)%*

The 2019 labour variance was primarily due to employees being temporarily reassigned to other departments to assist with lingering clean-up from post-tropical storm Dorian. The 2019 non-labour variance was primarily due to lower-than-expected material and supply costs.

The 2020 variance was driven by a decrease in non-labour costs, which was primarily due to lower-than-expected material and supply costs.

The 2021 variance was driven by a decrease in labour costs, primarily due to lower-than-planned weather-related repairs.

Table C-52 is a breakdown of forecast communication systems costs for 2022 to 2025.

TABLE C-52 Communications Systems 2022 and GRA Forecast ($000, expect %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Labour	138	16	(17)	142	4	145	3	149	4
Contractors	3	3	-	3	-	3	-	3	-
Non-labour	110	(4)	(5)	113	3	116	3	119	3
Total	**251**	**15**	**(22)**	**258**	**7**	**264**	**6**	**271**	**7**
Variance %		*6%*	*(8)%*		*3%*		*2%*		*3%*

The 2022 forecast does not materially vary from the prior year actual or forecast.

The 2023 to 2025 forecasts are based on a normalization of historical actuals adjusted for inflation.

C.4.8 Supervisory SCADA

This category provides for the maintenance of the supervisory control and data acquisition ("SCADA") system, which transmits data from the distribution and transmission system through the communication system to the Energy Control Centre. Equipment inspection and maintenance and licensing fees account for the majority of the expenditures.

Table C-53 provides a breakdown of historical costs associated with supervisory SCADA.

TABLE C-53 Supervisory SCADA Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	83	63	(20)	69	65	(4)	100	75	(25)
Non-labour	30	26	(4)	29	28	(1)	31	26	(5)
Total	**113**	**89**	**(24)**	**98**	**93**	**(5)**	**131**	**101**	**(30)**
Variance %			*(21)%*			*(5)%*			*(23)%*

The 2019 variance was driven by lower labour costs, which was primarily due to employees being temporarily reassigned to other departments to assist with lingering clean-up from post-tropical storm Dorian.

The 2020 costs did not vary materially from forecast.

The 2021 variance was driven by lower labour costs, which was primarily due to a vacant position that was filled in 2022.

Table C-54 provides a breakdown of forecast costs associated with supervisory SCADA for 2022 to 2025.

TABLE C-54
Supervisory SCADA
2022 and GRA Forecast ($000, expect %)

	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	89	14	(11)	91	2	94	3	96	2
Non-labour	32	6	1	33	1	34	1	35	1
Total	**121**	**20**	**(10)**	**124**	**3**	**128**	**4**	**131**	**3**
Variance %		*20%*	*(8)%*		*2%*		*3%*		*2%*

The 2022 forecast does not vary materially from the prior year actual or forecast.

The 2023 to 2025 forecasts are based on a normalization of historical costs adjusted for inflation.

C.4.9 Engineering

This category provides for the engineering support and analysis required to design, operate and maintain the distribution system, which is substantially labour and related costs. Activities include fuse coordination studies, power flow and voltage support analysis to ensure lines meet CSA standards, changing protection equipment settings to meet load growth and overall distribution system oversight and planning not associated with capital projects.

Table C-55 provides a breakdown of historical engineering costs.

TABLE C-55
Engineering
Historical Results ($000, expect %)

	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	313	275	(38)	310	301	(9)	354	303	(51)
Contractors	-	-	-	-	-	-	-	9	9
Non-labour	85	75	(10)	120	65	(55)	90	73	(17)
Total	**398**	**350**	**(48)**	**430**	**366**	**(64)**	**444**	**385**	**(59)**
Variance %			*(12)%*			*(15)%*			*(13)%*

The 2019 variance was driven by lower labour costs, which was mainly due to retirements that were not replaced until 2020.

The 2020 variance was driven by lower non-labour costs, which was mainly due to lower-than-planned training costs associated with pandemic-related travel restrictions.

The 2021 variance was driven by lower labour costs, which related to a parental leave that was not backfilled. The 2021 non-labour variance was primarily due to lower-than-planned training costs associated with pandemic-related travel restrictions.

Table C-56 provides a breakdown of forecast engineering costs for 2022 to 2025.

TABLE C-56 Engineering 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	358	55	4	386	28	408	22	418	10
Contractors	-	(9)	-	-	-	-	-	-	-
Non-labour	84	11	(6)	86	2	89	3	91	2
Total	**442**	**57**	**(2)**	**472**	**30**	**497**	**25**	**509**	**12**
Variance %		*15%*	*-%*		*7%*		*5%*		*2%*

The 2022 variance compared to the prior year actual was primarily due to higher labour costs, which reflect an employee returning from parental leave. The 2022 forecast does not vary materially from the prior year forecast.

The 2023 and 2024 variances are primarily due to higher labour costs that reflect a proportionate allocation of two additional junior engineers in mid-2023, who are required to support the capital program and operating requirements.[21] The remaining increases in 2023 to 2025 reflect an inflationary increase to historical actuals.

C.5 Other Transmission and Distribution Costs

Table C-57 provides a breakdown of historical costs associated with insurance, property tax and employee training.

[21] The cost of the two engineers is shared between transmission and distribution engineering.

TABLE C-57 Other Transmission and Distribution Costs Historical Results ($000, expect %)									
	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Insurance	124	144	20	166	166	-	131	203	72
Property Tax	2,022	2,050	28	2,125	2,125	-	2,279	2,213	(66)
Employee Training	86	100	14	72	73	1	91	97	6
Total	**2,232**	**2,294**	**62**	**2,363**	**2,364**	**1**	**2,501**	**2,513**	**12**
Variance %			*3%*			*-%*			*-%*

Insurance

Insurance cost reflects the necessary coverage available for the Company's transmission and distribution system substation assets. Insurance is procured by Fortis Inc. on behalf of its group members, which allows Maritime Electric to obtain insurance coverage that is economically priced. The buying power of Fortis Inc. provides an insurance cost that is much lower than what the Company could procure if it were seeking coverage independently.

Insurance premiums were higher than planned in 2019 due to challenging renewal markets following catastrophic weather events and wild fires experienced in North America.

Property Tax

Property taxes relate to the land on which the Company's transmission and distribution assets are located. Property tax is levied as either a tax on physical properties based on their assessed values or a revenue-related tax calculated at 1.0 per cent of the Company's annual revenue from the prior year. The revenue-related tax is used as a proxy for the taxation of the Company's transmission and distribution assets situated on public rights of way.

Property taxes in 2019 and 2020 did not vary materially from forecast. The 2021 variance was primarily due to the impact of lower-than-expected revenue in 2020 as a result of the onset of the pandemic, upon which property tax was assessed.

Employee Training

Employee training ensures a skilled workforce required to maintain a reliable transmission and distribution system.

The 2019 variance related to additional training for line personnel to refresh skills in response to safety incidents experienced in the field. The 2020 and 2021 costs did not vary materially from forecast.

Table C-58 provides a breakdown of forecast costs associated with insurance, property tax and employee training for 2022 to 2025.

TABLE C-58
Other Transmission and Distribution Costs
2022 and GRA Forecast ($000, expect %)

	2022			2023		2024		2025	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Insurance	226	23	95	239	13	252	13	266	14
Property Tax	2,273	60	(6)	2,358	85	2,515	157	2,642	127
Employee Training	94	(3)	3	96	2	99	3	101	2
Total	**2,593**	**80**	**92**	**2,693**	**100**	**2,866**	**173**	**3,009**	**143**
Variance %		*3%*	*4%*		*4%*		*6%*		*5%*

With respect to insurance, the 2022 forecast reflects an annual premium increase effective July 2021. Annual premium increases are expected to be above inflation over the 2022 to 2025 period at approximately 5 per cent.

With respect to property taxes, the forecast is based on the assessment criteria of one per cent of the Company's gross revenues from the prior year.

With respect to employee training, the 2022 to 2025 forecasts reflect a return to pre-pandemic training levels adjusted for inflation.

C.6 General and Administrative Costs

General and administrative costs are comprised of internal and external costs required to support the overall operation and management of the Company.[22]

Table C-59 outlines the general and administrative expense for the 2019 to 2025.

SCHEDULE C-59 General and Administrative Costs ($000)							
	2019 Actual	**2020 Actual**	**2021 Actual**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**
Customer Service	1,923	1,852	2,285	2,123	2,174	2,226	2,277
Finance	1,392	1,414	1,314	1,405	1,440	1,476	1,512
Corporate Communications	414	475	712	840	820	843	861
Information Technology	695	699	898	917	939	962	987
Regulation	1,065	1,020	1,141	1,305	1,331	1,357	1,385
Directors' Fees	365	390	413	523	536	550	563
General Property	692	770	787	809	830	851	872
Corporate Services	2,938	4,014	4,779	4,932	5,115	5,294	5,515
Total	**9,484**	**10,634**	**12,329**	**12,854**	**13,185**	**13,559**	**13,972**

Over the rate-setting period, general and administrative costs are forecast to increase by an average of 2.8 per cent per year.

C.6.1 Customer Service

This category provides for the customer service and meter reading functions. Costs include internal labour, benefits, training costs, fees paid to collection agents, damage claims, materials and supplies, bill payment processing costs related to collection of overdue accounts, customer communications costs, bad debt expense, meter reading device maintenance costs, and transportation costs related to meter reading.

Table C-60 provides a breakdown of historical customer service costs.

[22] In Order UE09-02 the Commission disallowed, for the purpose of determining the Company's regulated revenue requirement, all Fortis Inc. head office administrative costs charged to Maritime Electric. Therefore, all costs presented in this section do not contain any Fortis Inc. administrative costs.

TABLE C-60 Customer Service Historical Results ($000, expect %)									
	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Labour	1,608	1,519	(89)	1,535	1,459	(76)	1,740	1,560	(180)
Non-labour	524	404	(120)	495	393	(102)	526	725	199
Total	**2,132**	**1,923**	**(209)**	**2,030**	**1,852**	**(178)**	**2,266**	**2,285**	**19**
Variance %			*(10)%*			*(9)%*			*1%*

The 2019 labour variance was primarily due to: (i) employees on parental leave replaced with temporary staff at lower rates; (ii) delays in replacing retired employees; and (iii) employees temporarily reassigned to other areas of the Company to cover sick leave and relieve temporary work load requirements. The 2019 non-labour variance was primarily due to lower-than-expected bad debt expenses, training and travel costs and damage claim payouts.

The 2020 labour variance was primarily due to the unplanned retirement of a supervisor early in 2020. Similar to 2019, the 2020 non-labour variance was primarily due to lower-than-expected bad debt expenses and damage claims payouts.

The 2021 labour variance was primarily due to: (i) the unplanned retirement of a supervisor early in 2020; (ii) lower overtime as a result of fewer weather-related outages; (iii) employees temporarily reassigned to other areas of the Company; and (iv) the replacement of meter readers on sick leave with lower cost temporary employees. The non-labour variance was primarily due to an increase in bad debt expense of $194 thousand, which was associated with one large customer that went into receivership in 2021.

Table C-61 provides a breakdown of forecast customer service costs for 2022 to 2025.

TABLE C-61 Customer Service 2022 and GRA Forecast ($000, expect %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Labour	1,673	113	(67)	1,716	43	1,760	44	1,803	43
Non-labour	450	(275)	(76)	458	8	466	8	474	8
Total	**2,123**	**(162)**	**(143)**	**2,174**	**51**	**2,226**	**52**	**2,277**	**51**
Variance %		*(7)%*	*(6)%*		*2%*		*2%*		*2%*

The 2022 forecast did not vary materially from the prior year actual and forecast. The 2022 non-labour variance compared to the prior year actual was due to a one-time bad debt expense of $194 thousand recorded in 2021, partially offset by higher labour costs reflecting the expected return to a normal level of weather-related overtime.

The 2023 to 2025 forecasts reflect inflationary adjustments while non-labour costs have been reduced to reflect the 2019 and 2021 trend with respect to bad debt expense and damage claims.

C.6.2 Finance

This category provides for the reporting of accurate and complete financial results along with the related internal controls. The costs include internal labour, benefits, training costs, costs associated with customer billing, bill printing and postage, and the cost of the annual external audit of the Company's financial statements and rate base calculations.

Table C-62 provides a breakdown of historical finance department costs.

TABLE C-62 Finance Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	813	778	(35)	829	810	(19)	773	689	(84)
Non-labour	685	614	(71)	621	604	(17)	750	625	(125)
Total	**1,498**	**1,392**	**(106)**	**1,450**	**1,414**	**(36)**	**1,523**	**1,314**	**(209)**
Variance %			*(7)%*			*(2)%*			*(14)%*

The 2019 labour variance was primarily due to an employee on parental leave for a portion of 2019 who was not replaced. The 2019 non-labour variance was due to lower-than-expected postage costs primarily as a result of an electronic billing campaign.

The 2020 costs did not vary materially from the forecast.

The 2021 labour variance was primarily due the retirement of three full-time union employees, partially offset by one full-time and one temporary replacement. The 2021 non-labour variance was primarily due to lower-than-expected postage costs primarily as a result of the electronic billing campaign.

Table C-63 provides a breakdown of forecast finance costs for 2022 to 2025.

TABLE C-63 Finance 2022 and GRA Forecast ($000, expect %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Labour	746	57	(27)	764	18	783	19	803	20
Non-labour	659	34	(91)	676	17	693	17	709	16
Total	**1,405**	**91**	**(118)**	**1,440**	**35**	**1,476**	**36**	**1,512**	**36**
Variance %		*7%*	*(8)%*		*2%*		*3%*		*2%*

The 2022 variance compared to the prior year actual is driven by higher labour costs, which reflect the permanent replacement of one full-time union employee who retired in 2020. The 2022 variance compared to the prior year forecast was primarily due to lower non-labour costs, which reflects forecast postage costs in line with 2021 actual costs.

The 2023 to 2025 forecasts reflect inflationary adjustments, partially offset by a reduction in postage costs based on historical actuals.

C.6.3 Corporate Communications

This category provides for all aspects of communicating with and disseminating information to customers and other stakeholders regarding the services provided by the Company. The costs include internal labour, benefits, training costs, donations to support Island charities and community activities. From 2020 this category also includes the Company's sustainability activities.

In 2020 the Company initiated the process of obtaining the Sustainable Electricity Company™ designation from Electricity Canada.[23] The designation demonstrates Maritime Electric's commitment to operating in a manner that supports sustainable development and continuous improvement. The Company used internal resources to complete the application process in 2020, including a detailed gap analysis on conformance to the ISO 26000 Guidance Document on Social Responsibility as well as stakeholder outreach and polling. Third-party auditors were engaged to verify the Company's analysis before the application was submitted to Electricity Canada.

Maritime Electric's designation was officially approved in early 2021, and the Company hired a Sustainability Engineer Coordinator to meet the ongoing reporting requirements necessary to maintain the designation. Other key sustainability costs include a climate adaptation study by a third-party consultant in 2022, and internal and external branding and marketing initiatives to demonstrate the new Sustainable Electricity Company™ logo.

Table C-64 provides a breakdown of historical corporate communication costs.

[23] Electricity Canada was formally known as Canadian Electrical Association or CEA.

TABLE C-64 Corporate Communications Historical Results ($000, expect %)									
	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Labour	132	160	28	175	182	7	221	354	133
Non-labour	315	254	(61)	285	293	8	311	358	47
Total	**447**	**414**	**(33)**	**460**	**475**	**15**	**532**	**712**	**180**
Variance %			*(7)%*			*3%*			*34%*

The 2019 labour variance reflects the addition of a temporary employee to perform marketing and community outreach services at a lower cost compared to engaging an external consultant, which contributed to the lower non-labour forecast. Lower-than-expected donations also contributed to the non-labour variance.

The 2020 costs did not vary materially from the forecast.

The 2021 labour variance was primarily due the addition of a marketing and community outreach coordinator in October 2020 and a sustainability engineer coordinator in April 2021. The 2021 non-labour costs did not vary materially from forecast.

Table C-65 provides a breakdown of forecast corporate communication costs for 2022 to 2025.

TABLE C-65 Corporate Communications 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	407	53	186	425	18	442	17	453	11
Non-labour	433	75	122	395	(38)	401	6	408	7
Total	**840**	**128**	**308**	**820**	**(20)**	**843**	**23**	**861**	**18**
Variance %		*18%*	*58%*		*(2)%*		*3%*		*2%*

The 2022 labour variance compared to the prior year actual was primarily due to the addition of a sustainability engineer in April 2021. The 2022 non-labour variance primarily reflects an increase for the annual Trees for Life program and a one-time provision in 2022 for a climate change study.

The 2022 labour variance compared to the prior year forecast reflects the addition of the marketing and community outreach coordinator in October 2020 and the sustainability engineer coordinator in April 2021, both of whom were not contemplated when the 2021 forecast was developed. The 2022 non-labour variance is due to: (i) a one-time provision in 2022 for a climate change study; (ii) a Trees for Life tree planting campaign; and (iii) sustainability benchmarking.

The 2023 to 2025 forecasts are based on a normalization of historical costs adjusted for inflation. The 2023 non-labour forecast is lower than the prior year forecast reflecting the one-time provision in 2022 for a climate change study.

C.6.4 Information Technology

This category provides for the management of technology systems that support the entire Company, such as work planning, customer information and billing, service order management, outage management and dispatching as well as cybersecurity and website management. The information technology category also reflects the costs of supporting the business network infrastructure, which includes backups, security, patching and disaster recovery strategies. The costs include internal labour, benefits, training costs, as well as costs associated with certain ongoing software maintenance agreements required to maintain key technology systems.

Table C-66 provides a breakdown of historical information technology costs.

TABLE C-66 Information Technology Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	360	325	(35)	367	336	(31)	442	526	84
Non-labour	421	370	(51)	397	363	(34)	380	372	(8)
Total	**781**	**695**	**(86)**	**764**	**699**	**(65)**	**822**	**898**	**76**
Variance %			*(11)%*			*(9)%*			*9%*

The 2019 and 2020 labour variances were primarily due to the reassignment of resources to assist external consultants on certain capital projects. The 2019 and 2020 non-labour variances were primarily due to lower-than-expected costs related to an annual cybersecurity risk assessment, on-going maintenance fees, and training costs.

The 2021 labour variance was primarily due to expensing labour costs of $57 thousand associated with two capital projects that were cancelled and the reassignment of resources back to operational requirements to monitor net metering requests, which increased significantly since government incentives were introduced in August 2020.[24] The 2021 non-labour costs did not vary materially from forecast.

Table C-67 provides a breakdown of forecast information technology costs for 2022 to 2025.

[24] The two cancelled capital projects were the Work Management System and On-line Services, which were cancelled as it was determined that the planned replacement of the legacy customer information and billing system will include integrated ancillary software applications for both these services, as submitted to the Commission in the 2021 Capital Variance Report.

TABLE C-67 Information Technology 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	474	(52)	32	486	12	498	12	511	13
Non-labour	443	71	63	453	10	464	11	476	12
Total	**917**	**19**	**95**	**939**	**22**	**962**	**23**	**987**	**25**
Variance %		*2%*	*12%*		*2%*		*2%*		*3%*

The 2022 forecast does not vary materially from the prior year actual. The decrease in labour costs reflects the fact that 2021 labour was higher as noted above. This decrease is offset by higher non-labour costs associated with cybersecurity consulting services.

The 2022 labour variance compared to the prior year forecast is primarily due to the addition of a full-time entry-level position to address increased cybersecurity activities. The 2022 non-labour variance is primarily due to cybersecurity consulting services.

The 2023 to 2025 forecasts reflect inflationary adjustments to historical actuals.

C.6.5 Regulation

This category reflects internal and external resources associated with regulatory filings and proceedings as well as the annual IRAC assessment.

Table C-68 provides a breakdown of historical regulatory costs.

TABLE C-68 Regulation Historical Results ($000, expect %)									
	2019			2020			2021		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Labour	200	185	(15)	196	194	(2)	297	291	(6)
Non-labour	883	880	(3)	739	826	87	770	850	80
Total	**1,083**	**1,065**	**(18)**	**935**	**1,020**	**85**	**1,067**	**1,141**	**74**
Variance %			*(2)%*			*9%*			*7%*

The 2019 costs did not vary materially from forecast. The 2020 and 2021 variances were driven by higher non-labour costs, which was due to a higher-than-planned IRAC assessments.

Table C-69 provides a breakdown of forecast regulatory costs for 2022 to 2025.

TABLE C-69 Regulation 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	418	127	121	434	16	450	16	467	17
Non-labour	887	37	117	897	10	907	10	918	11
Total	**1,305**	**164**	**238**	**1,331**	**26**	**1,357**	**26**	**1,385**	**28**
Variance %		*14%*	*22%*		*2%*		*2%*		*2%*

The 2022 labour variances compared to the prior year actual and forecast reflect the addition of a full-time professional position to address an increased workload related to the number and sophistication of regulatory requirements. The 2022 non-labour variance reflects an annual IRAC assessment consistent with recent years actual.

The 2023 to 2025 forecasts are based on historical actuals adjusted for inflation, with the exception of the forecast of IRAC assessments which is held at the 2022 forecast amount.

C.6.6 Directors' Fees

This category provides for Maritime Electric's Board of Directors fees and related expenses. Directors' fees are reviewed periodically to ensure they remain competitive, enabling the Company to attract highly skilled individuals to serve on the Board.

Table C-70 provides a breakdown of historical Directors' fees and related expenses.

TABLE C-70
Directors' Fees
Historical Results ($000, expect %)

	2019			2020			2021		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Labour	373	333	(40)	384	378	(6)	396	400	4
Non-labour	35	32	(3)	21	12	(9)	37	13	(24)
Total	**408**	**365**	**(43)**	**405**	**390**	**(15)**	**433**	**413**	**(20)**
Variance %			*(11)%*			*(4)%*			*(5)%*

The 2019 variance was primarily due to lower-than-planned labour costs as the forecast anticipated a fee increase that was not actually effective until mid-2019.

The 2020 and 2021 costs did not vary materially from forecast. However, non-labour costs in both 2020 and 2021 were lower than forecast due to pandemic-related travel restrictions preventing out-of-province directors from attending board meetings in person.

Table C-71 provides a breakdown of forecast Directors' fees for 2022 to 2025.

TABLE C-71 Directors' Fees 2022 and GRA Forecast ($000, expect %)									
	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Labour	486	86	90	498	12	511	13	523	12
Non-Labour	37	24	-	38	1	39	1	40	1
Total	**523**	**110**	**90**	**536**	**13**	**550**	**14**	**563**	**13**
Variance %		*27%*	*21%*		*2%*		*3%*		*2%*

The 2022 labour variances compared to the prior year actual and forecast reflect a periodic review and resulting increase in directors' fees effective January 2022. The 2022 non-labour variances reflects an anticipated return to normal travel for out-of-province directors.

The 2023 to 2025 forecasts reflect inflationary adjustments to historical actuals.

C.6.7 General Property

This category provides for the operation and maintenance of the Company's main office, district offices and substation buildings. The costs include general maintenance, janitorial services, security, fire prevention, elevator repair and maintenance, snow removal, heating, ventilation and air conditioning and other miscellaneous costs as well as the property taxes associated with these properties.[25]

Table C-72 provides a breakdown of historical general property costs.

[25] Property taxes related to generating, distribution and transmission activities are discussed in Sections C.1.9 and C.5.

TABLE C-72 General Property Historical Results ($000, expect %)									
	2019			**2020**			**2021**		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Maintenance	489	478	(11)	501	553	52	520	567	47
Property Tax	222	214	(8)	285	217	(68)	235	220	(15)
Total	**711**	**692**	**(19)**	**786**	**770**	**(16)**	**755**	**787**	**32**
Variance %			*(3)%*			*(2)%*			*4%*

The 2019 costs did not vary materially from forecast.

The 2020 and 2021 increases in maintenance costs were a direct result of the pandemic, with increased cleaning and sanitation costs required for all properties and the rental of portable washrooms for a period of time to allow physical distancing. These increases were partially offset by lower-than-expected property tax assessments.

Table C-73 provides a breakdown of forecast general property costs for 2022 to 2025.

TABLE C-73 General Property 2022 and GRA Forecast ($000, expect %)									
	2022			**2023**		**2024**		**2025**	
	Forecast	**Variance vs Prior Year Actual**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**	**Forecast**	**Variance vs Prior Year Forecast**
Maintenance	583	16	63	598	15	613	15	629	16
Property Tax	226	6	(9)	232	6	238	6	243	5
Total	**809**	**22**	**54**	**830**	**21**	**851**	**21**	**872**	**21**
Variance %		*3%*	*7%*		*3%*		*3%*		*2%*

The 2022 variance compared to the prior year actual reflects inflationary adjustments, while the variance compared to the prior year forecast is higher as the 2021 forecast did not contemplate the increase caused by pandemic-related activities.

The 2023 to 2025 forecasts are based on a normalization of historical costs adjusted for inflation.

C.6.8 Corporate Services

This category includes labour costs for the executive and senior management associated with: human resources; internal audit; health, safety and environment; system planning; administrative support; and other organizational expenses. This category also includes general insurance costs, rating agency fees, trustee fees related to the Company's bonds, employee future benefits, general corporate legal fees and other general operating costs.[26]

Table C-74 provides a breakdown of historical corporate service costs.

TABLE C-74
Corporate Services
Historical Results ($000, expect %)

	2019			2020			2021		
	Forecast	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**
Employee Future Benefit Costs	(988)	(1,088)	(100)	37	61	24	862	752	(110)
Employee Training	25	(23)	(48)	40	22	(18)	26	38	12
Human Resources	175	198	23	187	203	16	192	225	33
Insurance	40	39	(1)	45	46	1	43	53	10
Legal	178	209	31	294	303	9	211	95	(116)
Corporate Services	2,896	3,149	253	3,104	2,912	(192)	3,112	3,061	(51)
Heath, Safety and Environment	109	129	20	150	123	(27)	154	128	(26)
Internal Audit	94	90	(4)	98	101	3	101	126	25
System Planning	190	235	45	252	243	(9)	264	301	37
Total	**2,719**	**2,938**	**219**	**4,207**	**4,014**	**(193)**	**4,965**	**4,779**	**(186)**
Variance %			*8%*			*(5)%*			*(4)%*

[26] Insurance costs specific to the generation, distribution and transmission equipment are discussed in Sections C.1.9 and C.5.

Employee Future Benefit Costs

Employee future benefit costs in 2019 reflect the final full year of amortization of an actuarial gain and 2020 reflects a final half year amortization of the actuarial gain.[27]

The 2019, 2020 and 2021 variances compared to forecast reflect actual benefit payments as well as changes to plan estimates and assumptions provided by Morneau Shepell, the Company's actuarial expert.

Employee Training

The 2019 variance was primarily due to the receipt of funding from SkillsPEI in 2019 for training costs incurred in 2018. The 2020 variance was due to pandemic-related travel restrictions. The 2021 variance related to executive training and an employee enrolled in a Masters of Business Administration program that had not been contemplated in the forecast.[28]

Human Resources

The 2019 variance reflects higher-than-expected legal costs related to union contract negotiations. The 2020 and 2021 variances reflect higher-than-expected arbitration costs and consulting fees related to programs to support employee total health and psychological safety.

Insurance

Since 2008, the Company participates in a Fortis Inc. insurance program which allows Maritime Electric to obtain insurance coverage at much lower cost than what the Company could procure if it were seeking coverage independently.

Insurance premiums in 2019 and 2020 were consistent with forecast, and were higher than forecast in 2021 due to challenging renewal markets following catastrophic weather events and wild fires experienced in North America.

[27] Effective May 15, 2015, the Company implemented changes to the Employee Future Benefits Health Plan that resulted in an actuarial gain that was amortized over 2015 to 2020 as permitted by Order UE14-02.

[28] For an employee to qualify for up to 90 per cent funding for a Master's degree, the employee must exhibit leadership qualities, be accepted into a reputable degree program, obtain executive approval, and sign an agreement that stipulates that the employee will remain employed with Maritime Electric for a period of five years or repay a proportionate share of the funding received.

Legal

The 2019 variance reflects higher-than-planned legal costs due to an extended regulatory process related to the 2019 GRA. Conversely, legal costs were lower than planned in 2021 due to the anticipated filing of a GRA in 2021 that has been delayed until 2022.

Corporate Services

The 2019 variance was primarily due to increases in the relative valuation of the variable components of executive compensation. Conversely, the 2020 variance was primarily due to reductions in the relative valuation of the variable components of executive compensation as a result of changes to the executive team. The 2021 costs did not vary materially from forecast.

Health, Safety and Environment

The 2019 variance was primarily due to the addition of a new position in September 2019 to allow for the successful transition of knowledge before the existing superintendent retired. The 2020 variance was a result of the reassignment of the existing superintendent to lead the process for the Company's designation as a Sustainable Electricity Company™.[29]

The 2021 variance related to the new superintendent being on parental leave from May 2021 with the position being temporarily covered by an existing employee in another department. This decrease was partially offset by the subscription costs of a new working alone application initiated to ensure employee safety while working alone in the field. This software subscription is included in the information technology forecast on a go-forward basis.

Internal Audit

The 2019 and 2020 costs did not vary materially from forecast. The 2021 variance was due to higher-than-planned labour costs related to replacing the internal auditor and an internal audit software licensing increase.

System Planning

The 2019 variance was primarily due to the addition of a new planning engineer in September 2018, who had not been contemplated in the forecast. This new position was necessary to assist

[29] The existing superintendent retired in April 2021.

with an increased workload related to the expanding electrical system. The 2020 costs did not vary materially from forecast. The 2021 variance was primarily due to the addition of a new position, Manager of Capital Planning and Reporting, to assist with the increased regulatory capital workload.[30]

Table C-75 provides a breakdown of forecast corporate service costs for 2022 to 2025.

TABLE C-75
Corporate Services
2022 and GRA Forecast ($000, expect %)

	2022			2023		2024		2025	
	Forecast	Variance vs Prior Year Actual	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast	Forecast	Variance vs Prior Year Forecast
Employee Future Benefit Costs	663	(89)	(199)	681	18	701	20	725	24
Employee Training	59	21	33	51	(8)	31	(20)	31	-
Human Resources	219	(6)	27	227	8	232	5	239	7
Insurance	58	5	15	61	3	64	3	68	4
Legal	301	206	90	223	(78)	228	5	324	96
Corporate Services	2,961	(100)	(151)	3,205	244	3,353	148	3,426	73
Heath, Safety and Environment	180	52	26	125	(55)	129	4	132	3
Internal Audit	124	(2)	23	128	4	131	3	134	3
System Planning	367	66	103	414	47	425	11	436	11
Total	**4,932**	**153**	**(33)**	**5,115**	**183**	**5,294**	**179**	**5,515**	**221**
Variance %		*3%*	*(1)%*		*4%*		*4%*		*4%*

Overall, the 2022 corporate services forecast does not vary materially from the prior year actual or forecast, as several variances are forecast to offset each other.

The 2023 to 2025 forecasts reflect inflationary increases along with the normal variability of these types of costs.

30 A portion of labour cost of the Manager of Capital Planning and Reporting is allocated to capital projects via General Expense Capitalized.

Employee Future Benefit Costs

The reduction in the 2022 forecast is based on the estimated costs provided in the December 31, 2021 actuarial report prepared by Morneau Shepell. The 2023 to 2025 forecasts reflect inflationary increases.

Employee Training

The 2022 and 2023 forecasts reflect an employee enrolled in a master's degree program. The 2023 to 2025 forecasts reflect inflationary increases and a return to pre-pandemic training levels.

Human Resources

The 2022 forecast was increased compared to the prior year forecast to reflect recent experience for legal and consulting fees related to union contract negotiations and arbitration. The 2023 to 2025 forecasts reflect inflationary increases.

Insurance

The 2022 forecast reflects the annual premium increase that was effective July 2021.[31] The 2023 to 2025 forecasts reflect an expected annual increase of approximately 5 per cent, as predicted by Fortis Inc.'s insurance specialist.

Legal

The 2022 and 2025 forecasts reflect additional legal fees related to GRA preparation and hearing costs and are based on actual costs incurred in 2020. The 2023 and 2024 forecasts are based on actual costs incurred in non-GRA years.

Corporate Services

The forecast variances for 2022 to 2025 are primarily the result of changes in executive compensation costs due to the relative valuation of variable compensation components and recent changes to the executive team. All other costs are adjusted to reflect inflationary increases of approximately 2.5 per cent.

[31] The insurance premium covers a period from July 1 to June 30 annually.

Health, Safety and Environment

The 2022 forecast reflects a one-time increase of $40 thousand for a safety evaluation.[32] The 2023 to 2025 forecasts reflect inflationary increases.

Internal Audit

The 2022 to 2025 forecasts reflect inflationary increases.

System Planning

The 2022 forecast reflects an increase of $50 thousand for a third-party engineering study to assess the impacts of renewables and intermittent generation on the Company's electrical system. The 2023 to 2025 forecasts reflect inflationary increases.

[32] The Engine Room Operation Safety Diagnostic (Safety Evaluation Process) provides a targeted evaluation of how an organization functions with respect to all facets of operational safety performance including strategy, culture, processes, leadership capability, systems, metrics, programs and operational execution.

APPENDIX D

2020 DEPRECIATION STUDY

OVERVIEW

This analysis of the 2020 Depreciation Study is provided to explain how it impacts the proposed depreciation expense in the General Rate Application ("GRA" or the "Application") seeking approval of customer rates effective March 1, 2023 to February 28, 2026.

Background

From May 1, 1994 to December 31, 2003, the Company operated under a price cap regulatory model in accordance with the provisions of the *Maritime Electric Company Limited Regulation Act*. Through legislative changes, the Company returned to cost-of-service regulation under the provisions of the *Electric Power Act* effective January 1, 2004. Section 23 of the *Electric Power Act* states that:

> *"Every public utility shall carry a proper and adequate depreciation account when the Commission, after investigation, determines that the depreciation account can be reasonably required; the Commission shall ascertain and determine what are proper and adequate rates of depreciation of the several classes of property of each public utility."*

Proper and adequate depreciation requires the Company to maintain depreciation accounts whereby, over the useful service life of its assets, the original capital cost of each asset is recovered from customers via depreciation expense as a cost of providing electricity service. Depreciation expense is calculated by applying an appropriate depreciation rate to the original capital cost of each asset class. Under good utility practice, proposed changes to depreciation rates are brought to the regulator based on an expert evaluation (i.e., a depreciation study).

Since returning to cost-of-service regulation, the Company has filed with the Commission four depreciation studies prepared by Gannett Fleming, a depreciation expert. The first study, filed in August 2006, was based on results as of December 31, 2005. By Order UE07-01, the Commission ordered that the existing depreciation rates remain in effect until otherwise ordered.

The second study, filed in July 2015, was based on results as of December 31, 2014 (the "2014 Depreciation Study") and recommended revised depreciation rates be adopted in 2016. The revised depreciation rates reflected the remaining average service life of each asset class and included a prudent allowance for the cost of removing the assets upon retirement. The 2014 Depreciation Study also recommended that depreciation rates incorporate the amortization of a portion of the accumulated reserve variance, which was estimated to be approximately $33.4 million. The accumulated reserve variance represents the difference between the Company's recorded accumulated depreciation and the theoretical reserve calculated by Gannett Fleming.

The adoption of all of the recommendations in the 2014 Depreciation Study would have resulted in a significant increase in depreciation expense. Therefore, the Company instead proposed the adoption of the recommended depreciation rates excluding the amortization of the accumulated reserve variance on all asset classes except for the Charlottetown Thermal Generating Station ("CTGS"). The Company believed that its proposal struck a reasonable balance between the impact of higher depreciation expense on customer electricity costs and the need to fully depreciate the CTGS assets prior to the facility's closure and decommissioning. By Order UE16-04, the Commission approved the depreciation rates as proposed by the Company.

The third study, filed in June 2018, was based on results as of December 31, 2017 (the "2017 Depreciation Study") and recommended revised depreciation rates be adopted in 2019. Similar to the previous depreciation study, the Company felt the impact of adopting all the recommendations of the 2017 Depreciation Study would result in a significant increase in customer electricity costs and to mitigate that impact the Company proposed deferring some of the study's recommendations.

The Company's proposed mitigations were as follows:

1. Recover the accumulated reserve variance associated with the CTGS of $16.2 million over a five-year period from 2019 to 2023, via a regulatory deferral account, instead of the 2017 Depreciation Study's recommendation that it be recovered over a four-year period from 2018 to 2021. The Company's proposal anticipated the required regulatory process to review the 2017 Depreciation Study and the 2019 GRA that would prevent the study's recommendation from being implemented as proposed and instead would result in the $16.2 million being recovered over a three-year period from 2019 to 2021. In addition, by extending the recovery period to 2023, the accumulated reserve variance would be

recovered over a period of time that included the related decommissioning activities.

2. Defer the recovery of the accumulated reserve variance of $27.7 million associated with all remaining assets.

The Commission did not agree with the mitigations proposed and, by Order UE19-08, ordered that the depreciation rates recommended in the 2017 Depreciation Study be fully adopted as of January 1, 2020.

The fourth study, filed in July 2021, was based on results as of December 31, 2020 (the "2020 Depreciation Study") and is discussed in the following section.

2020 Depreciation Study Results

The 2020 Depreciation Study used the straight-line method for calculating depreciation using the average service life methodology, consistent with previous studies. The resulting calculations were based upon attained ages and the estimated average service life and net salvage for each group of depreciable assets.[1]

The annual depreciation rates recommended incorporate the recovery of the assets' original capital cost over their average remaining service life along with a prudent allowance for the costs to remove the assets upon retirement, which is referred to as the net salvage percentage. The recommended changes in depreciation rates were driven by: (i) changes in the average service life and cost of removal assumptions; and (ii) a two-year delay in the implementation of the 2017 Depreciation Study.

Table D-1 summarizes the rates approved by the Commission in Order UE19-08, which includes the recommended amortization of the accumulated reserve variance, alongside the comparable rates currently recommended and as provided in Part VI of the 2020 Depreciation Study.

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1 Refer to the "Basis of the Study" section of the 2020 Depreciation Study, pages I-3 to I-6, for a detailed overview of the methodology used.

TABLE D-1		
Depreciation Rates by Asset Class		
Asset Class	**2020 Study Rate (%)**	**Existing Rate (%)**
Production Plant:		
CTGS[1]	-	13.06
Borden Generating Station	6.15	5.83
Combustion Turbine #3 (“CT3”)	2.64	2.49
Transmission Plant	2.64	2.42
Distribution Plant	3.84	3.72
General Plant	6.36	6.00
Composite Rate	**3.75**	**4.51**

[1] Due to the approved retirement of CTGS at the end of 2021, the depreciation rate recommended in the 2020 Depreciation Study for the CTGS will not need to be adopted.

Table D-2 summarizes the annual depreciation expense recommended in the 2020 Depreciation Study compared to the 2017 Depreciation Study.

TABLE D-2			
Annual Depreciation Expense by Asset Class			
Asset Class	**2020 Depreciation Study[2] ($ millions)**	**2017 Depreciation Study[3] ($ millions)**	**Variance ($ millions)**
Production Plant:			
Borden Generating Station	0.9	0.8	0.1
CT3	1.0	0.9	0.1
Transmission Plant	3.9	3.0	0.9
Distribution Plant	15.3	13.0	2.3
General Plant	3.4	2.6	0.8
Total Depreciation Expense	**24.5**	**20.3**	**4.2**

[2] Amounts taken from Table 3 of the 2020 Depreciation Study, which was filed with the Commission on July 29, 2021.

[3] Amounts taken from Table 3 of the 2017 Depreciation Study, which was filed with the Commission on June 29, 2018.

Table D-3 summarizes the composition of the recommended rates between depreciation and amortization of the accumulated reserve variance.

TABLE D-3 Annual Depreciation and Reserve Variance Amortization				
Asset Class	**Annual Depreciation ($ millions)**	**Reserve Variance Amortization ($ millions)**	**Total Annual Depreciation ($ millions)**	**Annual Depreciation Rate (%)**
Production Plant:				
Borden Generating Station	0.6	0.3	0.9	6.15
CT3	0.9	0.1	1.0	2.64
Transmission Plant	3.8	0.1	3.9	2.64
Distribution Plant	14.0	1.3	15.3	3.84
General Plant	3.3	0.1	3.4	6.36
Total	**22.6**	**1.9**	**24.5**	**3.75**

Production Plant

The 2020 Depreciation Study includes recommended depreciation rates for the CTGS because this group of assets had a balance at December 31, 2020 and was included in the depreciable asset population. However, the recommendations concerning the CTGS do not need to be approved or adopted because these assets were retired on December 31, 2021 and the deferral of the undepreciated reverse balance was approved. Therefore, the recovery of the undepreciated reserve balance is addressed in Section 5.3.5 of this Application.

The Borden Generating Station consists of combustion turbines #1 and #2 (“CT1” and “CT2”), installed in 1971 and 1973 and related equipment, and CT3 is a combustion turbine that was installed in 2005 in Charlottetown. The 2020 Depreciation Study concluded that, based on the current and expected future mode of operation of these three combustion turbines, as primarily emergency standby units, the life span estimate is longer than industry norms. The estimated retirement dates for CT1 and CT2 of 2031 and for CT3 of 2056 are unchanged from the 2017 Depreciation Study.

The 2020 Depreciation Study recommends an immaterial change in the annual depreciation for the Borden Generating Station and CT3, per Table D-2.

Transmission Plant

Transmission plant is comprised of assets used to transmit electricity at higher voltages (generally at 69 kilovolts ("kV") and higher). Those assets include towers, poles, overhead conductor, substation equipment and rights of way.

Gannett Fleming's analysis determined that the Company's transmission assets attained ages that were slightly higher than previously expected and revised the survivor curves to reflect this. In addition, Gannett Fleming's analysis determined that the cost to remove these assets upon retirement was greater than previously expected and the net salvage percentage was increased to reflect this.

The 2020 Depreciation Study recommends an increase in the annual depreciation of transmission assets of $0.9 million, as per Table D-2, which also reflects the amortization of a reserve variance that increased $5 million compared to the 2017 Depreciation Study.

Distribution Plant

The Company's largest asset group, distribution plant, is comprised of assets used to transmit electricity at lower voltages (generally below 69 kV). Those assets include towers, poles, overhead and underground conductor, overhead and underground services, meters, transformers, substation equipment and rights of way.

Gannett Fleming's analysis determined that the Company's distribution assets generally attained ages that were slightly higher than previously expected, while some attained ages that were lower, and revised the survivor curves to reflect this.[4] In addition, Gannett Fleming's analysis determined that the cost to remove these assets upon retirement was greater than previously expected and the net salvage percentage was increased to reflect this.

[4] As per Table 1 in Gannett Flemming's 2020 Depreciation Study, the survivor curves for distribution asset groups 368.1, 369.01, 369.02, and 370.1 were revised to reflect a longer expected useful life, while the survivor curves for distribution asset groups 364 and 368.2 were revised to reflect a shorter expected useful life.

The 2020 Depreciation Study recommends an increase in the annual depreciation of distribution assets of $2.3 million, as per Table D-2, which also reflects the amortization of a reserve variance that increased $12 million compared to the 2017 Depreciation Study.

General Plant

General plant is comprised of the transportation equipment, communication equipment, buildings, office furniture and related equipment, and general tools.

Gannett Fleming's analysis determined that the survivor curves used in the 2017 Depreciation Study continue to be appropriate, indicating that the Company's general assets have attained ages that were consistent with expectations. In addition, Gannett Fleming's analysis determined the net salvage percentage for buildings and vehicles needed to be revised. The cost to remove parts of the buildings when retired was greater than previously expected and the positive salvage value attained when retired vehicles were sold was lower than previously expected.

The 2020 Depreciation Study recommends an increase in the annual depreciation of general assets of $0.8 million, as per Table D-2, which also reflects the amortization of a reserve variance that increased $1.5 million compared to the 2017 Depreciation Study.

Proposal

The Company recommends implementing the depreciation rates as proposed in the 2020 Depreciation Study, with the exception of the rates pertaining to the Charlottetown Steam Plant.

APPENDIX E

VEGETATION MANAGEMENT PROGRAM

OVERVIEW

Vegetation management is the practice of clearing trees and bushes from transmission and distribution rights of way to prevent outages caused by vegetation coming in contact with power lines and create a safe work space for power line technicians. As discussed in Section 4.2.3 of the 2023 General Rate Application ("Application"), over 50 per cent of Maritime Electric's outages are caused by wind and tree contacts, which suggests that improved tree clearances would have prevented many of these outages. Having trees in close proximity to power lines also presents a significant safety hazard for power line technicians.

The Company plans to address these reliability and safety concerns by significantly improving the vegetation management cycle and transitioning to a ten-year cycle for distribution and a seven-year cycle for transmission by 2027.[1] The evidence that follows will demonstrate that the 2021 operating budget for vegetation management is materially insufficient to allow for a vegetation management cycle in line with industry practice.

As discussed in Section 5.1.2 of the Application, the Company seeks approval to increase the operating budget for transmission and distribution rights of way from $1.8 million in 2021 to $4.0 million by 2025.[2]

Benefits of Expanded Vegetation Management

Expanding vegetation management will result in safety, reliability and cost benefits.

Safety is Maritime Electric's highest priority. Therefore, the safety benefits of a proper vegetation management cycle is a key driver in this plan. Proximity of trees to transmission or distribution lines increases the safety hazard for power line technicians and utility arborists who are required to work on or near the lines. Such proximity requires a layer of safety protocols including the use

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[1] A vegetation management cycle is the number of years between first trimming or ground cutting a right of way, when the distribution or transmission line was constructed and returning to trim or ground cut the vegetation growth. Good utility practice requires a higher reliability standard and, therefore, a shorter transmission cycle, compared to a distribution cycle, due to the impact on customer outages.

[2] The 2021 rights of way approved budget was composed of $1.4 million for distribution and $0.4 million for transmission. The proposed 2025 budget is composed of $3.4 million for distribution and $0.6 million for transmission.

of specialized equipment and protection permits. Managing vegetation prior to it reaching the power lines is the best way to reduce this hazard.

Reliability is increasingly important to customers and it is a key metric used by Maritime Electric to assess its performance.

Proper maintenance of the electrical system is necessary to provide an acceptable level of reliability for customers, and Electricity Canada (formally known as the Canadian Electrical Association) indicates that the industry average for tree-related outages from 2011 to 2021 was 14 per cent. In comparison, Maritime Electric outage statistics for that same period show that 33 per cent of reported outages, excluding the impact of post-tropical storm Dorian, were attributed to trees and/or wind, which is well above the industry average.

Maritime Electric's customers report reliability dissatisfaction as one of the key reasons for a poor opinion of the Company. This dissatisfaction can be linked to Maritime Electric's five-year rolling average for SAIDI (All In), which is trending upwards.[3] Reliability impacts increase significantly during major storm events where the effects of not achieving a reasonable vegetation management cycle are magnified and often result in longer restoration times.

Furthermore, as the Province transitions to the use of electricity as a clean fuel source and customers switch to electric heat sources and electric vehicles, the expectations for reliability will increase even beyond current levels. Therefore, without a reasonable vegetation management cycle customers' satisfaction is expected to deteriorate.

Cost efficiencies will be achieved with Maritime Electric's plan to enhance vegetation management. The proposal includes an increase in ground cutting. If an area is ground cut, it generally means vegetation management will not be needed for a longer period of time. In comparison, the Company's experience indicates that if an area is only trimmed, vegetation management could be needed in as little as three years. Therefore, ground cutting is more cost effective.

[3] SAIDI (All In) refers to System Average Interruption Duration Index under all operating conditions (i.e., including major system events) and is discussed in Section 4.2.2 of the Application.

In addition, by maintaining a reasonable vegetation management cycle even trimming activities will be more cost effective. Without a reasonable trimming cycle, costs to trim are generally one and a half to two times higher because the trees grow up and around the lines, which then requires protection permits and additional work safe procedures. Vegetation management activities performed after the trees reach energized lines is a suboptimal use of the existing budget.

Maritime Electric's Expanded Vegetation Management

The increased operating budget will allow Maritime Electric to: (i) shorten the vegetation management cycle; (ii) focus on ground cutting rather than trimming; (iii) complete a re-vegetation pilot project; and (iv) identify opportunities to recycle the cut vegetation.

Vegetation Management Cycle

Maritime Electric's 2021 rights of way budget of $1.8 million results in a 35-year cycle for distribution lines and a 14-year cycle for transmission lines.[4]

In assessing what would be a reasonable vegetation management cycle, the Company obtained information from other Atlantic Canadian utilities and a sister utility in the United States that have a similar vegetation profile as Prince Edward Island. Table E-1 provides some of the details of this research.

TABLE E-1
Utility Comparison – Distribution Vegetation Management

Utility[5]	Kilometers of Distribution A	2020 Budget B	Budget/km C = B/A	Cycle[6] (years)
Central Hudson (Fortis utility)	11,514	$ 25,300,000	$ 2,197	4.5
Nova Scotia Power[7]	25,000	25,000,000	1,000	8
NB Power	21,434	10,200,000	476	5 to 7
Maritime Electric[8]	5,780	1,376,400	238	35

[4] Distribution: $48.5 million (total cost from Table E-2) / $1.4 million (2021 budget) = 35 years; Transmission: $5.5 million (total cost from Table E-2) / $0.4 million (2021 budget) = 14 years.

[5] Newfoundland Power was not included in the analysis as their vegetation profile is not as densely populated and their growing cycle is shorter than Prince Edward Island.

[6] Hydro One in Ontario, which has a vegetation profile similar to Prince Edward Island, has a vegetation management cycle of six to eight years (https://www.hydroone.com/about/corporate-information/vegetation-management/practices).

[7] Nova Scotia Power's vegetation management program includes a budget to widen existing distribution rights of way, and the eight-year cycle is their target.

[8] Maritime Electric's kilometres of distribution is for over-head lines only.

As Table E-1 demonstrates, Maritime Electric's distribution vegetation management cycle is significantly higher than the other utilities, which averages six years. In addition, good utility practice recommends a vegetation management cycle of five to ten years, depending on the type of vegetation and climate. Climate change has resulted in warmer temperatures and longer growing seasons, which has resulted in utilities adjusting their vegetation management cycles to be more frequent than past practice.

To determine what it would cost to shorten the vegetation management cycle, Maritime Electric analyzed its vegetation management cost by span.[9]

In 2019 the Company completed a vegetation inspection of all of its off-road transmission system and almost half of its roadside transmission and distribution system. Extrapolating the results of this inspection, it is estimated that 60,600 distribution spans and 6,400 transmission spans require urgent vegetation management to avoid a significant deterioration of reliability.

Vegetation management includes two main cutting techniques: (i) trimming, which is cutting the trees and/or bushes such that they are three metres below the wire; and (ii) ground cutting, which is cutting the trees and/or bushes at ground level. Industry preference is to ground cut where possible because it is more cost effective.

Table E-2 calculates the total cost to appropriately address the 67,000 spans that require urgent vegetation management.

[9] A span refers to the area between two poles, in which the vegetation is located, and Maritime Electric has 10,333 transmission spans, of which 7,089 are roadside and 3,244 are off-road, and 79,733 distribution spans, which are mostly roadside.

TABLE E-2 Vegetation Management Costs			
	Trim	**Ground Cut**	**Total**
Distribution			
Number of Spans	48,500	12,100	60,600
Cost per Span	$ 700	$ 1,200	
Subtotal	**$ 33,950,000**	**$ 14,520,000**	**$ 48,470,000**
Transmission			
Number of Spans	4,300	2,100	6,400
Cost per Span	$ 700	$ 1,200	
Subtotal	**$ 3,010,000**	**$ 2,520,000**	**$ 5,530,000**
Total			**$ 54,000,000**

The Company first considered a target cycle of six years for the distribution system, consistent with average of the utilities in Table E-1. Based on an estimated total distribution cost of $48.5 million, achieving a distribution vegetation management cycle of six years would require an annual budget of $8.1 million. The Company considered an increase of approximately $6.7 million to be too high for customers.[10]

Alternatively, achieving a 10-year cycle for the distribution system, the upper end of industry practice and 7 years for the transmission system would lower the required budget increase while still achieving an acceptable vegetation management cycle necessary to ensure reliability. This option would require a one-time increase of $3.4 million for distribution and $0.4 million for transmission, which is still a significant one-time increase for customers.[11]

As an alternative, the Company considered a gradual transition over a five-year period to the required annual amount. Therefore, the Application proposes that the annual rights of way budget be increased by approximately $0.7 million annually until it reaches $4.0 million in 2025, as shown in Table E-3.[12]

[10] $8.1 million less $1.4 million (2021 distribution budget) = $6.7 million.

[11] Distribution: $48.5 million / 10 years = $4.9 million/year compared to $1.4 million (2021 distribution budget) = $3.5 million increase; Transmission: $5.5 million / 7 years = $0.8 million/year compared to $0.4 million (2021 transmission budget) = $0.4 million increase.

[12] $4.0 million (2025 proposed transmission and distribution budget) less $1.8 million (2021 transmission and distribution budget) = $2.2 million / 3-year rate-setting period = $730 thousand per year.

TABLE E-3 Proposed Rights of Way Budget[13]				
	Kilometers A	Budget B	Budget/km C = B/A	Cycle (years)
2021 Distribution Budget	5,780	$ 1,435,700	$ 248	35
2025 Proposed Distribution Budget	**5,780**	**3,362,000**	**582**	**14**
2027 Proposed Distribution Budget	**5,780**	**4,900,000**	**848**	**10**
2021 Transmission Budget	761	399,800	525	14
2025 Proposed Transmission Budget	**761**	**627,000**	**824**	**9**
2027 Proposed Transmission Budget	**761**	**790,000**	**1,038**	**7**

Ground Cutting versus Trimming

As discussed above, ground cutting is more cost effective. However, on Prince Edward Island ground cutting is not permitted in certain areas. Municipal Tree Protection Bylaws, the Migratory Bird Convention Act, Provincial Heritage Highways protection, and agricultural hedgerow requirements impose limitations on the Company's ability to ground cut. Furthermore, poles are located along the edge of the rights of way and vegetation management has been limited to within the boundary of the rights of way.

Nonetheless, the Company estimates that it can increase its ground cutting efforts to account for approximately 20 per cent of the distribution spans.

Efforts are underway to partner with the Provincial Government to enhance vegetation management activities. This initiative includes the Provincial Government making changes to the permitting process.[14] In addition, the Company is pursuing a collaboration with the department of Transportation and Infrastructure whereby their forestry staff would assume some of the vegetation management activities. The Company will also pursue increasing the width of the rights of way where possible by acquiring permission to ground cut or trim trees on private property, which will reduce the risk of trees just outside the rights of way falling into the power lines and causing an outage.

[13] This Application seeks approval of the 2025 proposed forecasts only. The 2027 proposed budgets are presented to show the ultimate achievement of the recommended vegetation management cycles.

[14] The Company must obtain a permit in advance of vegetation management activities within Provincial rights of way and the permit will be revised to favour ground cutting activities.

To increase the social acceptance of ground cutting, the Company plans to develop a customer information and social media campaign to publicize the importance of maintaining trees around power lines, to encourage customers to avoid planting under power lines, and to educate customers on the best low growth vegetation to plant near power lines. It has been Maritime Electric's practice to obtain agreement from the private land owner, whose land is adjacent to the provincially owned rights of way, before ground cutting within that right of way. In select areas where ground cutting is permitted by the government, the Company will revise this practice.

In addition, the Company plans to launch a tree replacement pilot project. This pilot project would provide trees to customers in exchange for permission to ground cut trees on private property when vegetation poses a high risk to the power lines. This initiative presents carbon offsetting tree planting opportunities. Beyond working with private land owners, potential partnerships and sites for replacement tree planting may develop, such as partnering with Island Nature Trust, Parks Canada and other government groups.

Transmission Line Re-vegetation Pilot Project

The Company plans to investigate the benefit of planting low growth vegetation and/or pollinating vegetation within transmission rights of way after ground cutting has been completed. It is expected that planting alternate vegetation will limit or prohibit the regrowth of trees and, thereby, extend the vegetation management cycle.[15]

If successful and cost effective, the Company will consider expanding such an effort to the remainder of the transmission and distribution rights of way.

Recycle

The Company plans to pursue opportunities to collaborate with community and government groups to recycle the wood and chips from vegetation management activities.

[15] Canadian Electricity Association – The Grid 2021, page 20: https://issuu.com/canadianelectricityassociation/docs/cea_thegrid_2021?fr=sN2QxMTE1ODE1MTU

Conclusion

The evidence presented supporting an increased operating budget for vegetation management activities to maintain and improve system reliability for the benefit of Maritime Electric's customers.

APPENDIX F

Cost of Capital Report

prepared by

Concentric Energy Advisors, Inc.

dated June 2022

REPORT:

COST OF CAPITAL

PREPARED FOR:

MARITIME ELECTRIC COMPANY, LIMITED

BEFORE THE:

ISLAND REGULATORY AND APPEALS COMMISSION

JUNE 2022

www.ceadvisors.com

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I. INTRODUCTION

A. Qualifications of Witnesses

My name is James M. Coyne, and I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752. I am testifying on behalf of the Maritime Electric Company, Limited ("Maritime Electric"), an indirect subsidiary of Fortis Inc.

I am among Concentric's professionals who provide expert testimony before federal, state and Canadian provincial agencies on matters pertaining to economics, finance, and public policy in the energy industry. Concentric provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. I regularly advise utilities, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes calculating the cost of capital for the purpose of ratemaking, and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, fuels and power markets. I have testified or provided expert evidence in state, provincial and federal jurisdictions in Canada and the U.S., including before the Island Regulatory and Appeals Commission (the "Commission"). This work has been provided on behalf of utilities, regulatory commissions, and staff.

I am also a frequent speaker and author of articles and white papers on the energy industry. For example, on behalf of the Canadian Gas Association and the Canadian Electricity Association, I prepared a discussion paper for utility executives and provincial regulators that examined the roles that Canada's utilities and regulators can play to promote innovation. In addition, I facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white papers to facilitate further discussion on emerging industry issues. I have been an invited speaker for several CAMPUT events, including the Energy Regulation Course at Queen's University where I spoke on "Innovations in Utility Business Models and Regulation."

In earlier positions, I served as Senior Economist for the Massachusetts Energy Facilities Siting Council, where I analyzed the supply plans and facilities proposals from the state's electric and gas utilities, and I also served as State Energy Economist for the Maine Office of Energy Resources.

I hold a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire. My qualifications are detailed more fully in Attachment 1.

My name is John P. Trogonoski, and I am employed by Concentric as an Assistant Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752. I am also testifying on behalf of Maritime Electric.

I provide expert testimony before U.S. state and Canadian provincial regulatory agencies on matters pertaining to finance, economics and public policy in the utility industry. I have testified or provided expert evidence on more than 25 occasions in various U.S. state and Canadian provincial jurisdictions, including before the Commission in the last Maritime Electric General Rate Application ("GRA"). This testimony has been provided on behalf of both utilities and regulatory commission staff.

Prior to joining Concentric, I was a member of the Staff of the Colorado Public Utilities Commission from 1999-2008, where I supervised the financial analysts in the energy and telecommunications sections, provided advisory services to the Commissioners on financial and economic matters, and filed expert testimony on rate of return, revenue requirement, cost allocation, rate design, incentive regulation, and public policy matters. I hold a master's degree in Business Administration and an undergraduate degree in Marketing from the University of Colorado at Denver. My qualifications are detailed more fully in Attachment 2.

B. Executive Summary

We have been asked to estimate the cost of capital for Maritime Electric for the purpose of establishing the required return on equity ("ROE") and capital structure for the proposed three year rate setting period from 2023 through 2025. In order to estimate the cost of capital, we have relied upon analytical tools and data sources normally used for such purposes before regulators in Canada and the U.S. We have also reviewed past decisions of the Commission in consideration of such matters. The analysis provided in this report supports our overall recommendation on the cost of equity and capital structure. That analysis includes the following:

1) Examination of the legal and regulatory requirements for determination of a fair rate of return;

2) An overview of economic and capital market conditions in Canada and the U.S. and the degree of integration between the economies of the two countries;

3) Selection of Canadian, U.S. and North American proxy groups comprised of companies that are risk comparable to Maritime Electric;

4) Estimation of the cost of common equity for the proxy group companies using the Discounted Cash Flow ("DCF") method, the Capital Asset Pricing Model ("CAPM"), and the Bond Yield Plus Risk Premium ("Risk Premium") approach;

5) Examination of authorized returns on equity for other investor-owned electric utilities in Canada and the U.S.;

6) Development of a range of results for the Canadian, U.S. and North American proxy groups; and

7) An assessment of the appropriateness of Maritime Electric's proposed capital structure based on a comparison to other investor-owned electric utilities in Canada and the U.S. and an examination of the Company's business and financial risks relative to the respective proxy groups.

As shown in Figure 1, the various ROE estimation models produce a range of results for the proxy group companies from 8.96 percent (Multi-Stage DCF results for U.S. Electric Utilities) to 12.08 percent (Constant Growth DCF results for Canadian Regulated Utilities). The average of all methods and proxy groups is 10.4 percent.

Figure 1: Summary of Results (including flotation costs)[1]

	Canadian Regulated Utilities	US Electric	North American Electric	Average
Constant Growth DCF	12.08%	9.77%	10.12%	10.7%
Multi-Stage DCF	10.48%	8.96%	9.21%	9.6%
CAPM	10.35%	10.79%	10.48%	10.5%
Risk Premium		10.01%	10.01%	10.0%
Average	11.0%	10.0%	10.1%	10.4%

The average of all methods for the U.S. Electric proxy group is 10.0 percent, within the range of 8.96 percent to 10.79 percent. We place the greatest reliance on this proxy group because it is most representative of Maritime Electric's business and financial risk profile. From within this range, the Company's proposed ROE of 9.95 percent is reasonable, if not conservative. The average for the Canadian regulated utilities proxy group, several of which have unregulated business activities and many of which do not own any regulated generation, is 11.0 percent, while the average for the North American Electric proxy group is 10.1 percent. The CAPM is producing higher return estimates at this time due to above average Beta coefficients for utilities in both Canada and the U.S., while the Multi-Stage DCF model is producing the lowest estimates due to projected GDP growth rates that are below historic averages.

Turning to capital structure, the Company has proposed a common equity ratio of 40.0 percent. Our analysis indicates this is lower than that justified by its risk profile and well below the average equity thickness for the U.S. Electric proxy group. The Company's risk profile is impacted by its small size relative to the companies in the Canadian and U.S. Electric proxy groups. The Company also operates in a service territory characterized by severe weather and ice storms, but does not have a deferral account or tracking mechanism for storm costs. The Company also lacks geographic and economic diversification, as noted by credit analysts.

Taken together, the proposed 9.95 percent ROE and 40.0 percent equity ratio would be at the lower end of estimates, in our judgment, that would satisfy the requirements of a fair return for Maritime Electric.

[1] DCF results are based on 90-day average stock prices for proxy group companies.

C.Report Organization

The remainder of our report is organized as follows:

- Section II discusses the legal requirements and regulatory precedents for the determination of a fair rate of return;
- Section III provides an overview of economic and capital market conditions and their impact on the models used to estimate the allowed ROE for Maritime Electric;
- Section IV describes the selection of proxy group companies to estimate the cost of equity for Maritime Electric and discusses the precedent in Canada for the use of U.S. data;
- Section V discusses the methods used to estimate the cost of equity and summarizes the results of the DCF, CAPM and Risk Premium methods, as well as allowed ROEs for other investor-owned electric utilities;
- Section VI provides an assessment of Maritime Electric's business and financial risks relative to the Canadian and U.S. proxy group companies and recommends an appropriate capital structure for the Company;
- Section VII describes the purpose of an earnings sharing mechanism and summarizes our research on other Canadian and U.S. utilities that employ such a mechanism; and
- Finally, Section VIII summarizes our overall conclusions and recommendations.

II. LEGAL REQUIREMENTS AND KEY REGULATORY PRECEDENTS FOR THE DETERMINATION OF A FAIR RETURN

A. The Fair Return Standard

The principles surrounding the concept of a "fair return" for a regulated company were established by the Supreme Court of Canada in *Northwestern Utilities v. City of Edmonton (1929)* S.C.R. 186 ("Northwestern"), where the Supreme Court found:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[2]

U.S. common law regarding fair return for utility cost of capital has evolved similarly. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the U.S. Supreme Court stated:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

The U.S. Supreme Court further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)), when it described the relevant criteria as follows:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

2 *Northwestern*, at 193.

Over time, the Fair Return Standard has been interpreted many times in both Canada and the U.S. For example, the National Energy Board ("NEB," now the Canada Energy Regulator) summarized its interpretation of the "fair return standard" in its RH-2-2004 Phase II Decision and reiterated that interpretation in its *Trans Québec & Maritimes Pipelines Inc.* RH-1-2008 Decision.

> The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).
>
> In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.[3]

All three standards must be met, and none ranks in priority to the others. To that point, the Ontario Energy Board ("OEB") articulated the legal requirements for satisfying the Fair Return Standard in Canada in its 2009 Generic Cost of Capital Order as follows:

> The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.[4]
>
> ***
>
> … all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through

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3 National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at 17.

4 Ontario Energy Board, EB-2009-084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at i.

> specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration of the comparability test is not sufficient to meet the [Fair Return Standard].[5]

This Commission embraces the same standards for the application of the Fair Return Standard as those put forth by the NEB, the OEB and those established through Canadian and U.S. common law. In that regard, the Commission stated in a 2009 decision for Maritime Electric:

> [59] The Commission in determining a fair return must try to assess the risk associated with the capital invested and the comments provided in the Northwestern Utilities case. Those comments make reference to the fact that the company will be allowed as large a return on the capital invested in its enterprise as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.
>
> [60] Regulators and courts have evolved a "fair return standard" in which returns have been set to help utilities provide safe and adequate services to the public at reasonable prices, while ensuring that the utilities involved remain a going concern with sufficient credit worthiness to attract capital needed to maintain and expand their facilities. A utility's duty to serve and the acceptance of the risk associated with this obligation cannot be discounted.[6]

In its 2019 Decision, Order UE 19-08 (at p. 16), the IRAC quoted the same language from the Supreme Court of Canada's *Northwestern* decision (cited two pages previously in this report) in which the Fair Return Standard was defined by the Court.

The assessment of whether the Fair Return Standard has been met requires an examination of the returns required by investors in comparable risk enterprises. Investors consider whether there are alternative investment opportunities that would provide a better return for the same risk. This weighing of alternatives and the highly competitive nature of capital markets causes stocks and bonds to settle on a price that provides investors with a return that is adequate for the risks involved. Thus, for any given level of risk, there is a corresponding return that investors expect in order to take on that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

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5 *Id.*, at 19.
6 The Island Regulatory and Appeals Commission, Docket UE20938, Order UE09-02, May 5, 2009, at 15.

In addition to setting the fair return at the "opportunity cost" of capital, a fair return must also be adequate to maintain the financial integrity of the utility, which requires a return sufficient to achieve credit metrics such that the utility can maintain a favorable credit rating in order to minimize debt costs and provide lenders assurance that the company's earnings are adequate to meet its fixed obligations. Finally, a fair return must be sufficient to attract incremental capital on reasonable terms and conditions, to the benefit of both investors and customers.

B. The Stand-Alone Principle

The Stand-Alone Principle is a finance principle that advocates for investors and companies selecting investments based on comparisons to other investments of similar risk. In utility regulation, this principle considers a utility as if it were a stand-alone entity, raising capital on the merits of its own business and financial characteristics. In this way, capital may be efficiently allocated, with each business segment earning a return based on its own unique set of risks and business characteristics regardless of affiliations within the holding company structure. In order to establish a fair return and satisfy the Stand-Alone Principle, the utility must be allowed a return sufficient to meet all three requirements of the Fair Return Standard on the basis of the utility's individual merits and risk profile.

C.Relationship between Capital Structure and Equity Return

The cost of common equity depends in part on the company's capital structure. The equity ratio and equity rate of return must therefore be considered together to determine whether the Fair Return Standard has been met. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate shareholders for the risks associated with higher financial leverage. Consequently, when a regulator approves a capital structure, that decision impacts the required rate of return on common equity.

The risk to the earnings stream of a company is a function of both its business and financial risk. Business risk refers to the political and regulatory environment in which the company operates and the operational and competitive forces that could potentially exert pressure on earnings and cash flows. Financial risk refers to the amount of debt in the utility's capital structure and the extent to which fixed debt obligations must be met before utility shareholders receive their returns. Both business and financial risk should be considered when setting the capital structure.

III. ECONOMIC AND CAPITAL MARKET CONDITIONS

A. Summary and Relevance to Utility Cost of Capital

Utilities raise debt and equity in an increasingly global market influenced by macroeconomic fundamentals, capital markets, and central bank policies. The cost of debt for utilities is observable, but the cost of equity must be estimated with an informed view of the macroeconomic and capital market factors that impact the analysis. Projections of real GDP growth, inflation and interest rates are direct inputs to the cost of capital models. Additionally, the cost of equity for regulated utilities is influenced by factors such as central bank policy, investor confidence, and uncertainty and volatility in financial markets. Each of these factors is discussed in this section of our report, starting with macroeconomic conditions in Canada and the U.S.

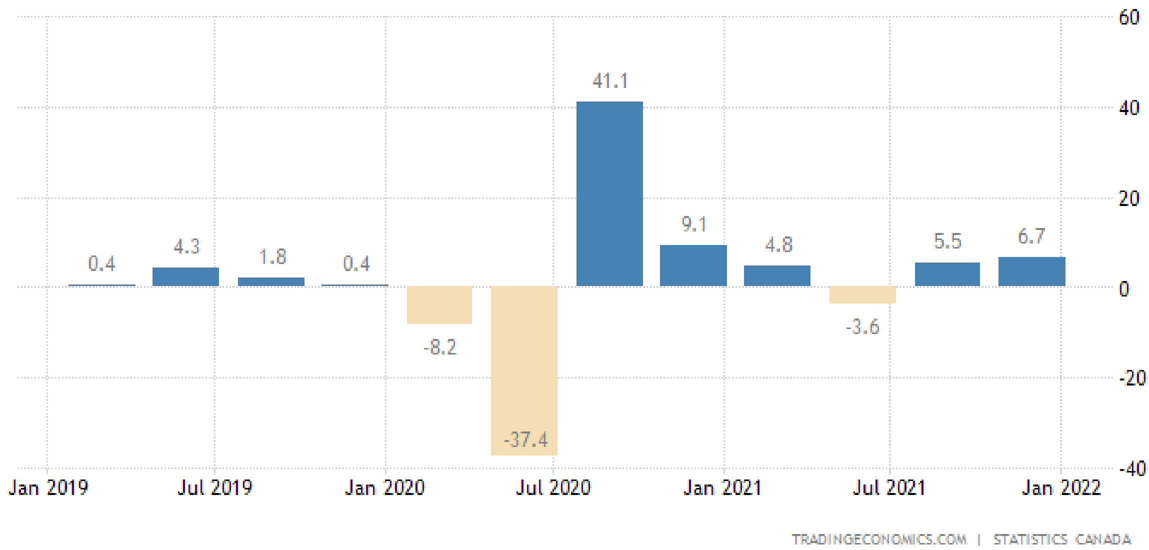
B. Changes in Capital Market Conditions since 2018

At the time of Maritime Electric's last GRA filing in November 2018, the economies in both Canada and the U.S. had recovered from the effects of the financial crisis and the Great Recession of 2008/2009, economic growth was steady but somewhat slower than after previous recessions, central banks in both countries were raising short-term interest rates, and the Federal Reserve was withdrawing some of the extraordinary monetary policy support that was needed to stimulate the U.S. economy. As of March 2022, the economies in both Canada and the U.S. have recovered from sharp contractions in 2020 that were precipitated by the COVID-19 pandemic, which forced the closure of many businesses as economies went into lockdown to control the spread of the virus. Vaccines were developed and distributed in both countries, and there is hope for continued economic improvement in 2022. However, extraordinary policy measures have been necessary from central banks and federal governments in both Canada and the U.S. to stabilize the financial system in the immediate aftermath of the pandemic, to support economic growth, and to provide additional unemployment benefits to those in industries most affected by COVID-19. This extraordinary policy response drove a precipitous drop in interest rates on government and corporate bonds. Those bond yields, however, have increased since July 2020 with economic recovery and increasing inflation.

1. Canada

In the wake of steady but slow growth in the Canadian economy in 2018 and 2019, Figure 2 shows that the economy contracted sharply in the first and second quarters of 2020 with the spread of COVID-19. This downturn represented the sharpest contraction ever recorded over the period from 1961-2020, according to Statistics Canada. On net, the Canadian economy shrank 5.4 percent in 2020. In the first quarter of 2021, real GDP in Canada grew at an annualized rate of 4.8 percent, but in the second quarter of 2021 real GDP again contracted at an annualized rate of 3.6 percent (compared to forecasts of 2.5 percent growth), raising doubts about the strength of the economic recovery. In the third and fourth quarters of 2021, real GDP once more grew at an annualized rate of 5.5 percent and 6.7 percent, respectively

Figure 2: Canadian Real GDP Growth[7]



The unemployment rate in Canada increased from 5.6 percent in February 2020 to 13.7 percent in May 2020, which represents the highest level for unemployment in Canada over the period from 1966-2020. As shown in Figure 3, the unemployment rate declined steadily for much of 2021. Unemployment now stands at 5.2 percent as of April 2022.

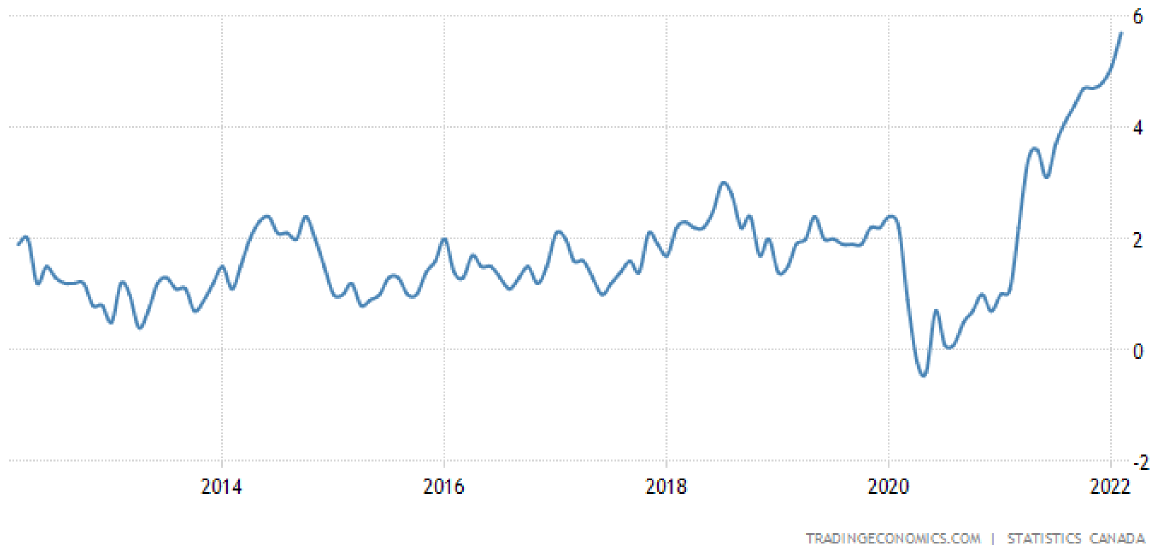
[7] https://tradingeconomics.com/canada/gdp-growth-annualized.

Figure 3: Canadian Unemployment Rate[8]

As shown in Figure 4, consumer prices in Canada generally have risen less than 2.0 percent in the past decade, but increased at a 30-year high of 4.8 percent in 2021 and at an annual rate of 6.7 percent for the 12 months ending in March 2022, the highest since January 1991.

8 https://tradingeconomics.com/canada/unemployment-rate.

Figure 4: Canadian Consumer Price Index[9]

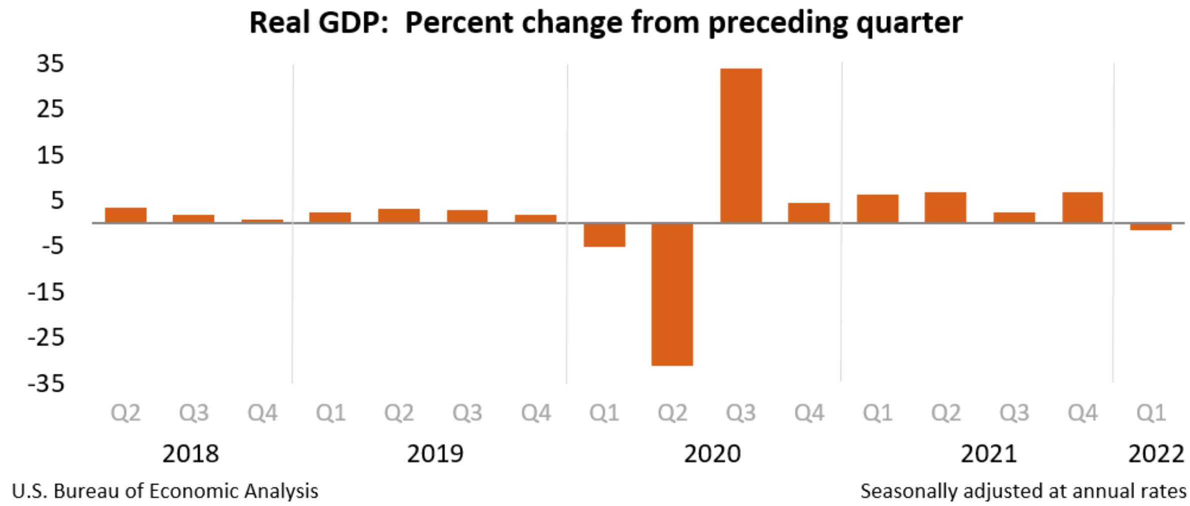


2. United States

After experiencing steady economic growth from 2017-2019, measures taken to contain COVID-19 and associated impacts on business and consumer behavior forced the U.S. economy into a sharp recession in 2020. As shown in Figure 5, GDP decreased at an annual rate of 5.0 percent in the first quarter of 2020 and at an annual rate of 31.4 percent in the second quarter of 2020 (the sharpest decline in modern history) before rebounding in the third and fourth quarters of 2020. GDP expanded in the first quarter of 2021 at an annual rate of 6.3 percent, in the second quarter of 2021 at an annual rate of 6.7 percent, slowed in the third quarter of 2021 to an annual rate of 2.3 percent, and accelerated again in the fourth quarter of 2021 at 6.9 percent. GDP decreased at an annual rate of 1.4 percent in the first quarter of 2022, as there was a resurgence of COVID-19 cases from the Omicron variant and decreases in government pandemic assistance payments.

9 https://tradingeconomics.com/canada/inflation-cpi .

Figure 5: U.S. Real GDP Growth[10]



As shown in Figure 6, the U.S. unemployment rate steadily declined over the past ten years from 9.1 percent in January 2011 to 3.6 percent in December 2019. After reaching a low of 3.5 percent

[10] U.S. Bureau of Economic Analysis, https://www.bea.gov/data/gdp/gross-domestic-product.

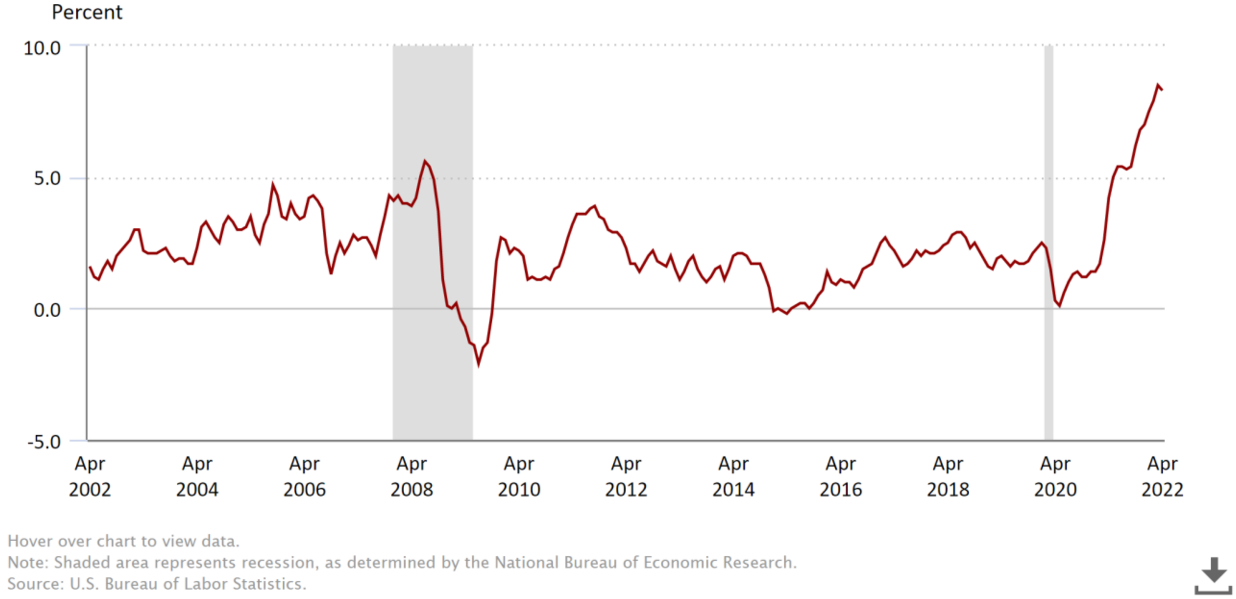
in January 2020, the unemployment rate spiked to 14.8 percent in April 2020 as businesses were forced to close due to COVID-19, before steadily falling to 3.6 percent in April 2022.

Figure 6: U.S. Unemployment Rate[11]

The Consumer Price Index in the U.S. increased at an annual rate of 1.8 percent in 2019 and 1.2 percent in 2020. The average annual increase in consumer prices from 2011 through 2020 was 1.73 percent. More recently, however, as shown in Figure 7, the U.S. Bureau of Labor Statistics reported that the CPI increased at an annualized rate of 8.3 percent before seasonal adjustment for the 12-month period ending April 2022, remaining at levels not seen since the early 1980s.[12]

[11] Source: U.S. Bureau of Labor Statistics.
[12] Source: U.S. Bureau of Labor Statistics.

Figure 7: U.S. Consumer Price Inflation
12-Month Change, Not Seasonally Adjusted[13]



C. Policy of Central Banks and Federal Government

In response to the economic effects of COVID-19, central banks and federal governments in both Canada and the U.S. took aggressive steps to stabilize financial markets in the Spring of 2020 and to provide ongoing support for the economies of both countries. This is important because it demonstrates that interest rates on government bonds have been driven by actions of central banks and not just the decisions of investors in the bond markets. For that reason, the use of an interest rate forecast or normalization is appropriate and necessary in order to better reflect the level of expected government bond yields as central banks in both Canada and the U.S. normalize their monetary policies over the next several years to combat higher inflation.

1. Canada

On March 2, 2022, the Bank of Canada ("BOC") announced that it was increasing the overnight rate by 25 basis points from 0.25 percent to 0.50 percent in response to inflation being higher than its target of 2.0 percent. The BOC also indicated that future increases to the overnight rate

[13] Source: U.S. Bureau of Labor Statistics.

should be expected.[14] This was the first increase in the overnight rate following the aggressive monetary policy response of the BOC to COVID-19, as described below.

On March 4, 2020, the Bank of Canada ("BOC") reduced its overnight target rate by 50 basis points from 1.75 percent to 1.25 percent. The BOC explained its rationale as follows:

> *Before the outbreak, the global economy was showing signs of stabilizing, as the Bank had projected in its January Monetary Policy Report (MPR). However, COVID-19 represents a significant health threat to people in a growing number of countries. In consequence, business activity in some regions has fallen sharply and supply chains have been disrupted. This has pulled down commodity prices and the Canadian dollar has depreciated. Global markets are reacting to the spread of the virus by repricing risk across a broad set of assets, making financial conditions less accommodative. It is likely that as the virus spreads, business and consumer confidence will deteriorate, further depressing activity.*[15]

This was followed by two further reductions of 50 basis points each in the BOC's overnight rate target on March 16, 2020 and March 27, 2020, bringing the overnight rate target from 1.25 percent to 0.25 percent. The BOC also engaged in Quantitative Easing for the first time ever, spending approximately $4 billion per month on purchases of government and corporate bonds. The BOC has increased its bond holdings by about $350 billion since the start of the pandemic. The amount of these purchases has been gradually reduced in recent months as conditions in the economy and financial markets have stabilized. On October 27, 2021, the BOC shifted course, announcing the end of its bond buying program and its intention to start increasing the overnight rate target earlier than expected, likely in "middle quarters" of 2022. In conjunction with this shift in monetary policy, the BOC revised higher its inflation forecast to 3.4 percent in both 2021 and 2022, while cutting its economic growth projections for both years primarily due to ongoing supply disruptions in the global economy.[16]

The federal government also took aggressive steps to provide fiscal stimulus during the course of the COVID-19 pandemic, providing financial assistance for both individuals and businesses. The Canadian government reported spending approximately $407 billion, or nearly 19 percent of Canada's GDP, on public health and direct income benefits.[17] In addition, the federal

[14] On April 13, 2022, the Bank of Canada increased the overnight rate by 50 basis points to 1.00 percent.
[15] Press release: Bank of Canada lowers overnight rate target to 1 ¼ percent, March 4, 2020.
[16] Bloomberg News, "Bank of Canada ends QE; moves up timeline for rate hike," October 27, 2021.
[17] Government of Canada, Fall Economic Statement 2020.

government announced plans to inject another $100 billion into the Canadian economy over the three years following the recession to ensure the sustainability of the economic recovery. While this policy response has provided crucial support for the Canadian economy, *The Wall Street Journal* reported in December 2020 that it caused the federal budget deficit in Canada to swell to approximately C$381.6 billion, or 17.5 percent of GDP, as compared with a deficit equal to 1.7 percent of GDP in the previous 12 month period. More recently, the finance ministry reported the budget deficit would be C$144.5 billion in fiscal 2021/22, down 6.6 percent from the C$154.7 billion forecast in April, as tax revenues increased and less emergency aid was used.[18] Due to concerns over the rapid increase in Canada's spending, Fitch downgraded the credit rating for Canada in June 2020 from AAA to AA+. However, Standard and Poor's ("S&P") and Moody's Investors Service ("Moody's") have maintained their AAA rating for Canada.[19]

In its April 2022 Monetary Policy Report, the BOC indicated that: "The Canadian economy continues to grow strongly. Growth in the second quarter is being boosted by the removal of public health restrictions, solid foreign demand and higher commodity prices." The BOC went on, underscoring its renewed focus on inflation: "A broad set of indicators suggests that slack has been absorbed and the economy is moving into excess demand. Faced with robust demand and supply constraints, firms are raising prices in response to higher input costs. This increases the risk that expectations of elevated inflation could become entrenched." Summarizing its overall outlook, the BOC concluded: "Overall, economic growth is robust and moderates through the projection horizon. Growth is expected to be 4¼% this year before slowing to a solid pace of 3¼% in 2023. A recovery in services consumption, exports and investment supports growth. At the same time, alongside the easing of supply constraints, strong investment and population growth are projected to strengthen potential output growth. In response to ongoing inflationary pressures, higher interest rates are expected to moderate growth in domestic demand to better align it with the growth of supply. GDP growth is projected to ease to about 2¼% in 2024."[20]

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[18] Reuters, "Canada sees smaller budget deficit, pushes promised spending to budget," December 14, 2021.

[19] The Wall Street Journal, "Canada's COVID-19 Response is to Spend Heavily and Ignore the Deficit – For Now," December 1, 2020.

[20] Bank of Canada *Monetary Policy Report*, April 2022.

2. United States

In March 2022, the U.S. Federal Reserve (the "Fed") also raised the federal funds rate by 25 basis points for the first time since 2018, and indicated that additional increases in the federal funds rate throughout the remainder of 2022 and in 2023 should be expected in order to combat higher than expected inflation, which the Fed had previously considered as "transitory."[21] This follows a prolonged period of monetary policy accommodation in the U.S., as discussed below.

In response to the economic effects of COVID-19, the Fed decreased the federal funds rate twice in March 2020, resulting in a target range of 0.00 percent to 0.25 percent and also announced plans to increase its holdings of both Treasury and mortgage-backed securities. In addition, on March 23, 2020, the Fed began expansive programs to 1) support credit to large employers, 2) provide liquidity for new issuances of corporate bonds, 3) to provide liquidity for outstanding corporate debt issuances, and 4) support the flow of credit to consumers and businesses through the Term Asset-Backed Securities Loan Facility.[22] These bond buying programs provided $700 billion in liquidity to financial markets, through purchases of government and corporate bonds and mortgage-backed securities. The Fed was buying $80 billion of Treasury bonds and $40 billion of mortgage-backed securities each month. On November 3, 2021, the Fed announced that it would begin "tapering" its bond buying program in November 2021, reducing the amount of monthly purchases by $15 billion. At the December 2021 FOMC meeting, the Fed announced that tapering would be accelerated by reducing monthly bond purchases by $30 billion, meaning that the bond buying program would conclude in March 2022.

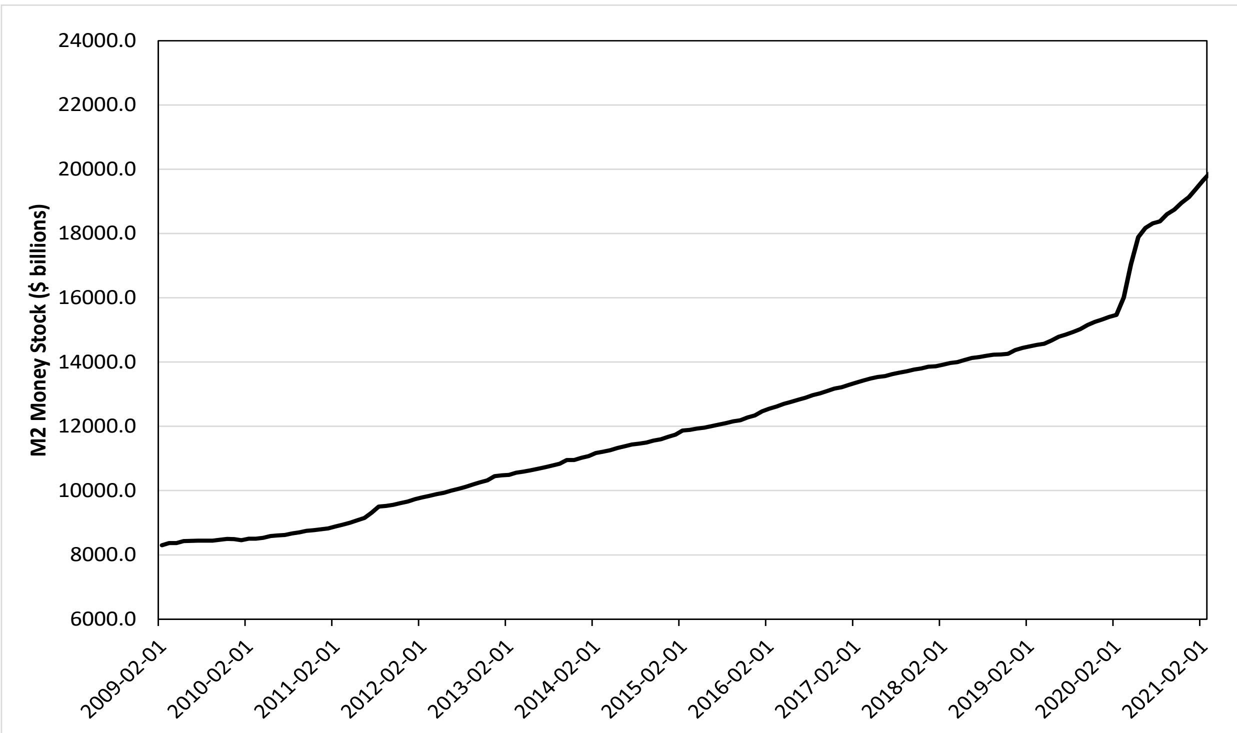
These "Quantitative Easing" programs allowed the Fed to purchase government and corporate bonds from banks. The banks then received cash from the Fed, which resulted in an expansion of the money supply. This increase in the money supply kept short-term interest rates low and increased the ability of banks to lend to consumers and businesses. Investors in longer term bonds also responded, which affected the entire duration of the yield curve, from very near-term rates all the way out to 30-year yields. Continued access to capital was particularly important because it allowed companies to offset the negative effects of COVID-19. Figure 8 shows that the

21 The Federal Reserve raised the federal funds rate by 50 basis points in April 2022.

22 Federal Reserve Board Press Release, "Federal Reserve announces extensive new measures to support the economy," March 23, 2020.

programs enacted by the Fed resulted in an unprecedented expansion of the money supply as measured by M2.[23] From January 2020 through February 2022, M2 expanded by approximately 41.8 percent. That expansion has been much greater than the increase following the Fed's response to the Great Recession of 2008/2009. This again demonstrates the level of intervention that was necessary to provide some stability to capital markets in 2020 and 2021.

Figure 8: M2 Money Stock – February 2009 – February 2022[24]



In addition to the Federal Reserve's response to COVID, the U.S. Congress also passed fiscal stimulus programs. On March 27, 2020, the Coronavirus Aid, Relief, and Economic Security Act was signed into law, providing a large fiscal stimulus package aimed at mitigating the economic effects of COVID-19. These expansive monetary and fiscal programs provided greater stability in capital markets; before they were implemented, volatility in equity markets had spiked to levels

[23] M2 is defined by the Federal Reserve as follows: M2 includes a broader set of financial assets held principally by households. M2 consists of M1 plus: (1) savings deposits (which include money market deposit accounts, or MMDAs); (2) small-denomination time deposits (time deposits in amounts of less than $100,000); and (3) balances in retail money market mutual funds (MMMFs).

[24] Board of Governors of the Federal Reserve System (US), M2 Money Stock [M2], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/M2, January 1, 2022.

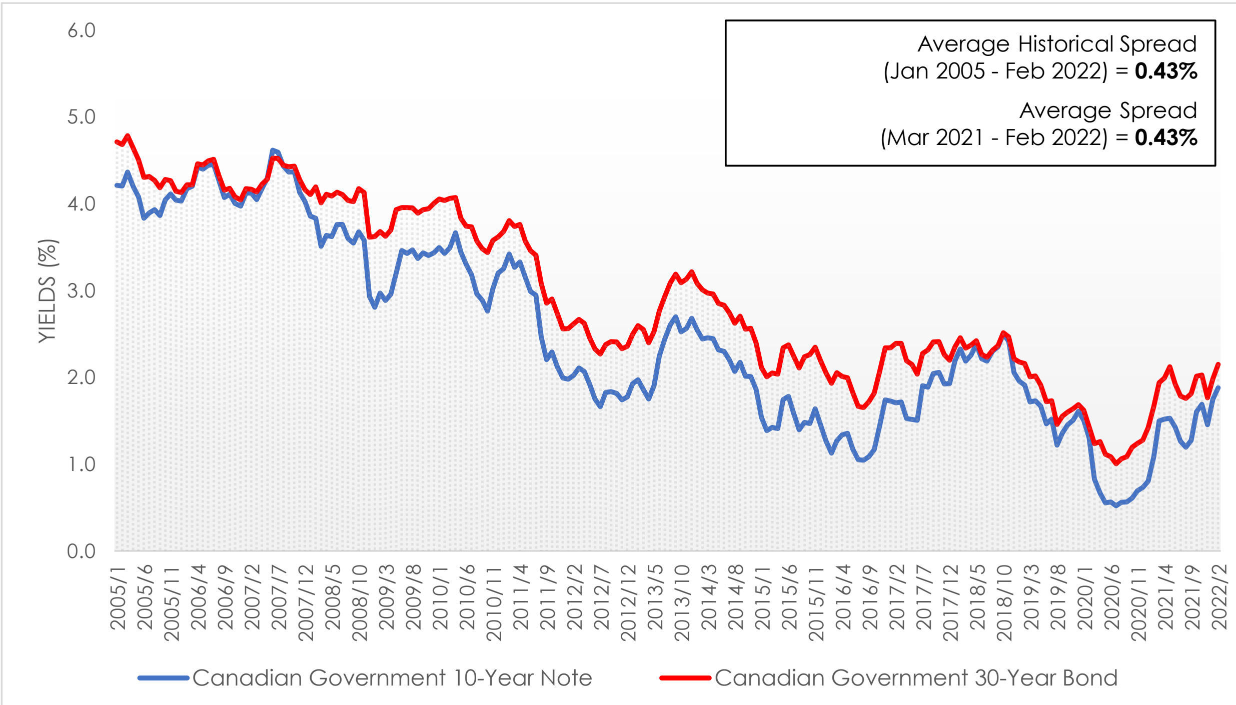
not seen since the Great Recession of 2008/2009. The extraordinary measures taken by the Federal Reserve to stabilize the economy and financial markets were successful, but in doing so drove investors from very low yielding bonds into equities, placing upward pressure on valuations and downward pressure on dividend yields for dividend paying companies such as utilities. Furthermore, in March 2021 the U.S. Congress approved an additional fiscal stimulus package of $1.9 trillion in response to the ongoing economic effects of COVID-19. Additional fiscal stimulus increased pressure on the inflation rate, and the bond market is carefully monitoring each economic report for signs regarding the future path of inflation.

D. Overview of Market Conditions

1. Interest Rates

Figure 9 shows that the average yield on 10-year Canadian government bonds decreased from 2.42 percent in November 2018 (when Maritime Electric filed evidence in the 2018 GRA) to 1.88 percent in February 2022, while the average yield on longer-term 30-year government bonds decreased from 2.47 percent to 2.15 percent over the same period. The spread between 10- and 30-year Canadian government bonds increased from 5 basis points in November 2018 to 27 basis points in February 2022, as compared with the historical average of 43 bps from January 2005 through February 2022. As Figure 9 shows, both the Canadian 10- and 30-year government bond yields increased sharply after trading at or near all-time lows in July 2020. The most recent data shows that the 10 and 30 year government bond yields have converged at higher levels, with both approaching 3.0% in mid-May 2022, as the yield curve has flattened beyond 10 years.

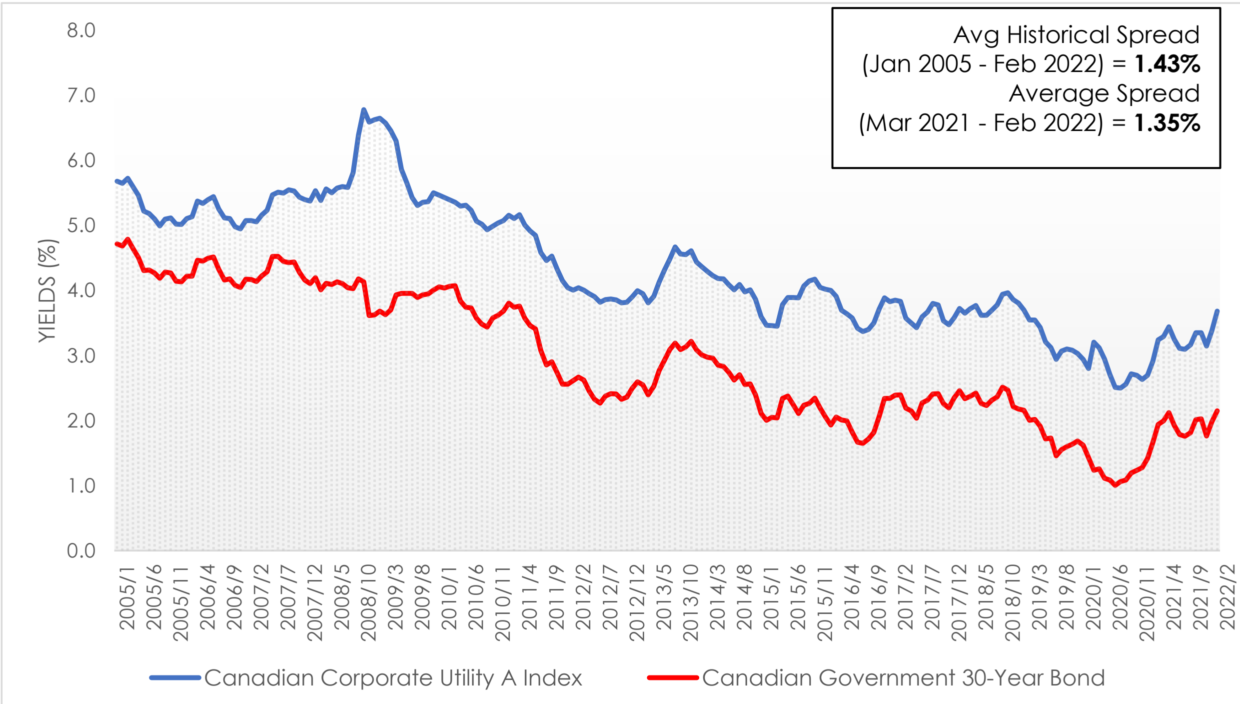
Figure 9: Canadian Government Bond Yields - 10-Year and 30-Year[25]



Yields on Canadian corporate bonds have also declined since November 2018. As Figure 10 illustrates, the Canadian Utility "A" rated bond yield index was 3.96 percent in November 2018 compared to 3.68 percent in February 2022, after reaching a low of 2.50 percent in August 2020. The spread between Canadian A-rated utility bonds and 30-year Canadian government bonds was 150 basis points in November 2018 as compared to 153 basis points in February 2022.

[25] Bloomberg series GCAN10YR and GCAN30YR as of February 28, 2022.

Figure 10: Canadian Utility "A" Rated Bond vs. 30-Year Canada Long Bond[26]



According to Consensus Economics' Long-Term Financial Forecast, shown in Figure 11, Canadian and U.S. 10-year government bond yields are expected to rise gradually to the 3.0-3.3% range reflecting movement towards more normalized economic policy in both countries.

Figure 11: Long-Term Forecast for 10-Year Government Bond Yields[27]

	2022	**2023**	**2024**	**2025**	**2026**	**2027-2031**
Canada	1.9%	2.3%	2.6%	2.8%	3.0%	3.0%
U.S.	2.1%	2.6%	2.9%	3.1%	3.2%	3.3%

2. Yield Curve

The yield curve measures the difference between long-term and short-term interest rates and is one of the leading indicators used by investors to determine the stage of the business cycle. A flat

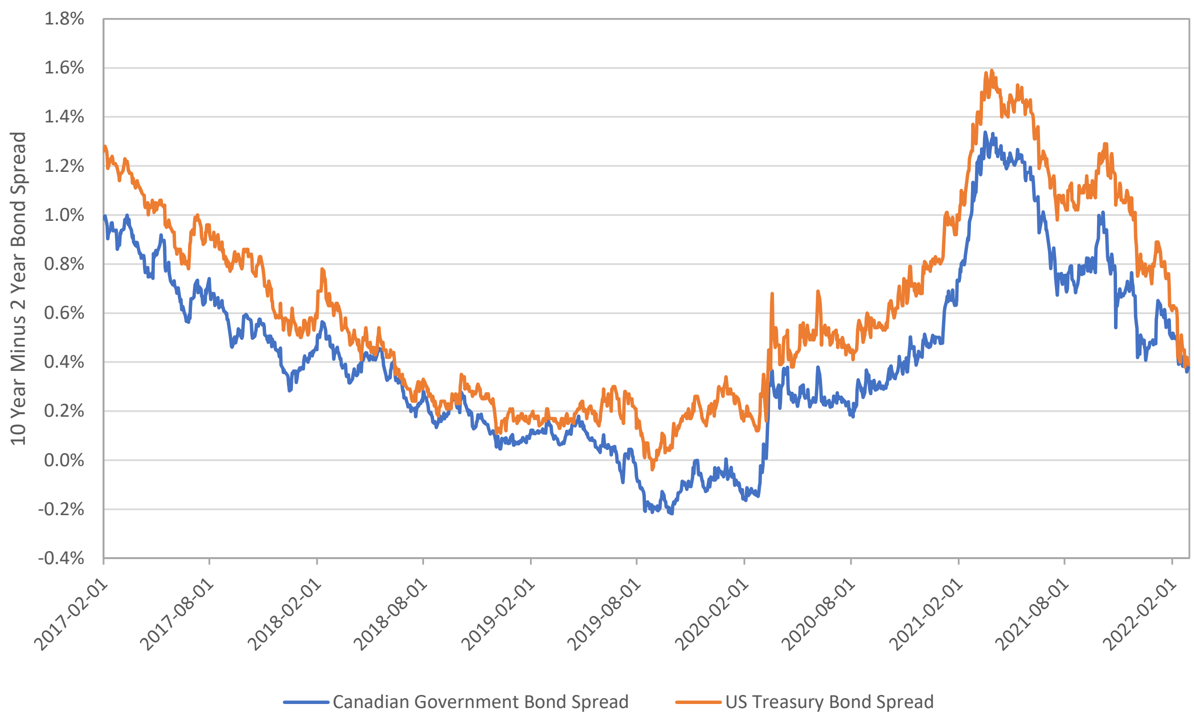
[26] Bloomberg series C29530Y and GCAN30YR as of February 28, 2022.
[27] Consensus Forecasts by Consensus Economics Inc., Survey Date October 11, 2021, at 3 and 28.

or inverted yield curve occurs when long-term interest rates are equal to or less than short-term interest rates, which usually occurs prior to a recession, while a steepening yield curve occurs when the difference between long-term interest rates and short-term interest rates is increasing and indicates that the economy is entering a period of economic expansion following a recession.[28] From a utility cost of capital standpoint, a steepening yield curve generally signals a higher cost of both equity and debt.

To test this measure, we calculated the difference between the yield on the 10-year government bond and the 2-year government bond ("bond spread") from February 2017 to February 2022. We selected the 10-year government bond yield to represent long-term interest rates and the 2-year government bond to represent short-term interest rates. The monthly bond spread in both Canada and the U.S. has increased between November 2018 and February 2022. In Canada, the bond spread was 15 basis points in November 2018 vs. 43 basis points in February 2022, while in the U.S. the monthly average bond spread was 26 basis points in November 2018 vs. 50 basis points in February 2022. In mid-May, the spread stood at 30 basis points. Even though this spread has receded from its recent highs in early 2022, the steeper yield curve indicates that investors expect stronger economic growth and higher inflation. As a result, they are expected to rotate out of long-term government bonds to avoid being locked into low interest rates for the long-term. Thus, higher yields are required by investors to invest in long-term government bonds.

[28] "What is a yield curve", Fidelity.com. https://www.fidelity.com/learning-center/investment-products/fixed-income-bonds/bond-yield-curve

Figure 12: 10-year Government Bond Yield Minus 2-year Bond Yield February 2017 – February 2022[29]



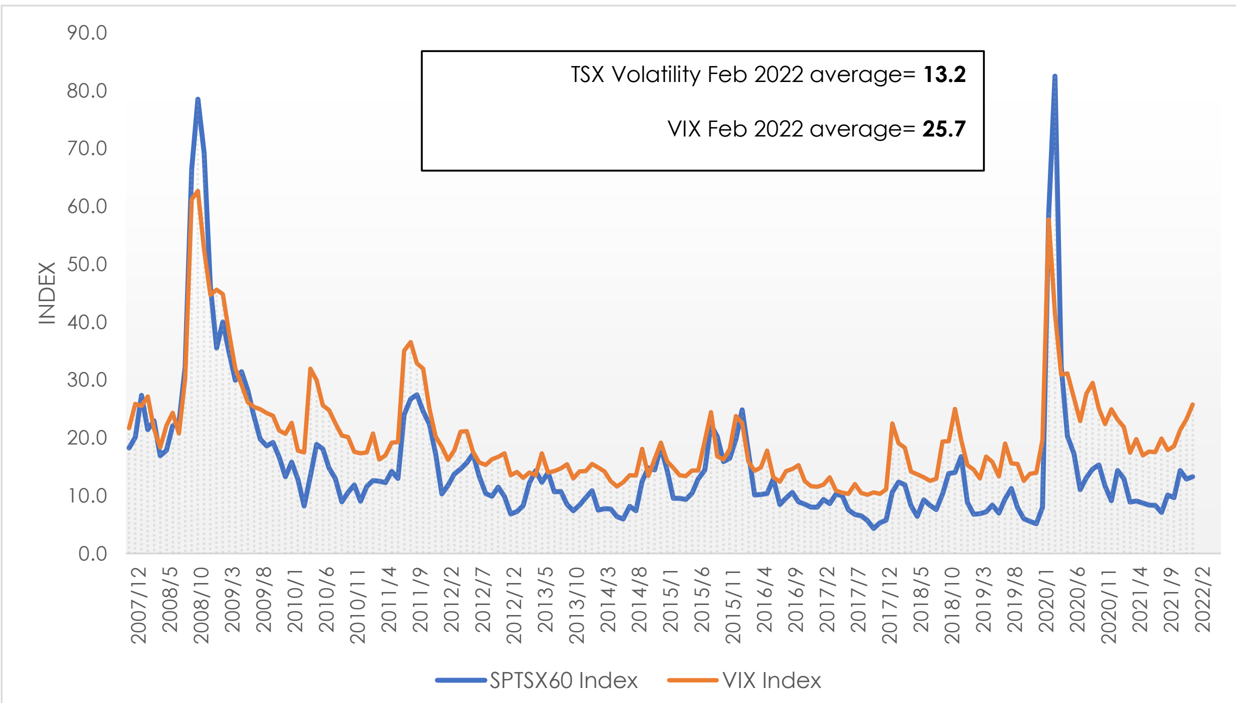
3. Volatility in Equity Prices

Stock prices in both Canada and the U.S. fell sharply from mid-February through April 2020, as investors reacted to fears over a global pandemic (the spread of COVID-19) and a sharp decline in crude oil prices. The TSX Composite Index declined by approximately 30 percent from February 20, 2020 through March 12, 2020, while the S&P 500 decreased by nearly 27 percent over the same period. Shares of utility companies also fell in both countries, with the TSX Utilities Index down by more than 26 percent and the S&P Utilities Index off by more than 23 percent. At the same time, volatility in equity markets spiked to levels not seen since the financial crisis and Great Recession of 2008-2009. As shown in Figure 13, volatility for the Canadian equity markets (as measured by the TSX Volatility Index) rose to an average of 82.50 in April 2020, while in the

[29] Federal Reserve Bank of St. Louis, 10-Year Treasury Constant Maturity Minus 2-Year Treasury Constant Maturity [T10Y2Y], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/T10Y2Y, February 28, 2022.

U.S. volatility (as measured by the VIX) followed a similar path, rising to an average of 57.74 in March 2020. As of February 2022, volatility had receded from extreme levels in both countries, but remains above the long-term median (12.3 in Canada and 17.6 in the U.S.). Since February volatility has again risen, no doubt influenced by the War in Ukraine, to 29.2 in the U.S. and 27.4 in Canada in mid-May. Without the extraordinary measures of central banks and governments to support the economies in Canada and the U.S. and stabilize financial markets, it is reasonable to assume that volatility would have remained elevated over the past 24 months.

Figure 13: Canadian and U.S. Volatility Indexes[30]



This sudden and dramatic spike in volatility in 2020 reflected the prevailing uncertainty and fear among equity investors. While volatility in equity markets declined in both Canada and the U.S. after it became apparent to investors that the aggressive monetary and fiscal policy response was having the desired impact on the economy and financial markets, there is ongoing uncertainty in financial markets. Inflationary pressure has increased in both Canada and the U.S. in recent months, and geopolitical events, such as the conflict between Russia and Ukraine, have caused a

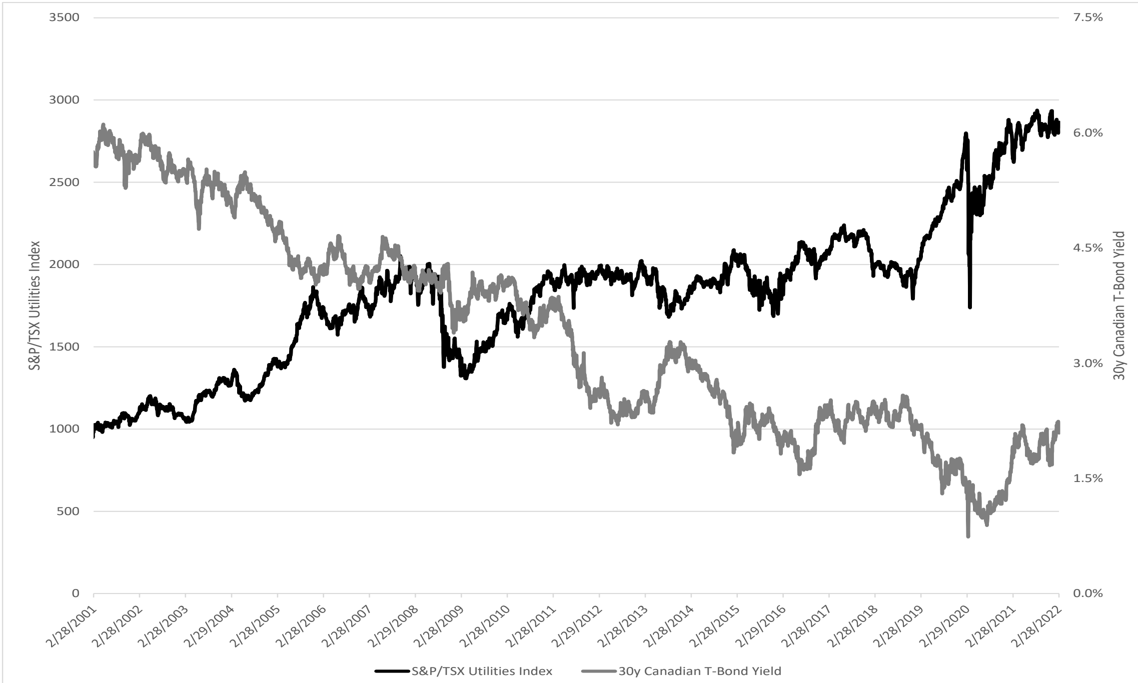
[30] Bloomberg Professional. Data through February 28, 2022.

spike in volatility, as oil prices have surged and global markets have declined significantly from near all-time highs. A key to ongoing market stability will be a gradual pullback from the accommodative monetary policies in both Canada and the U.S. while promoting continued economic growth.

4. High Valuations and Low Dividend Yields

The levels of long-term government bond yields have affected the valuations of utility shares in both Canada and the U.S. As shown in Figure 14, the 30-year Canadian government bond yielded more than 4.0 percent in 2008. Long Canada bond yields have declined steadily since then as central banks in Canada and around the world pursued a policy of monetary policy accommodation amid low inflation levels. In response, the TSX Utilities Index increased substantially as dividend paying stocks became more valuable to investors due to their higher dividend yields compared to yields on long Canada bonds. After reaching a trough in the summer of 2016, government bond yields in Canada started increasing and utility shares, as measured by the TSX Utilities Index, became less attractive relative to government bonds. More recently, the TSX Utilities Index declined sharply in March 2020 in response to concerns over COVID-19, but has since rebounded to new highs. Yields on 30-year Canadian government bonds also fell sharply in the Spring of 2020 as central banks eased monetary policy to offset the economic effects of the pandemic, but have increased in 2021 and 2022 as the Bank of Canada has started to increase the overnight rate in response to inflation well above target levels and strong employment data.

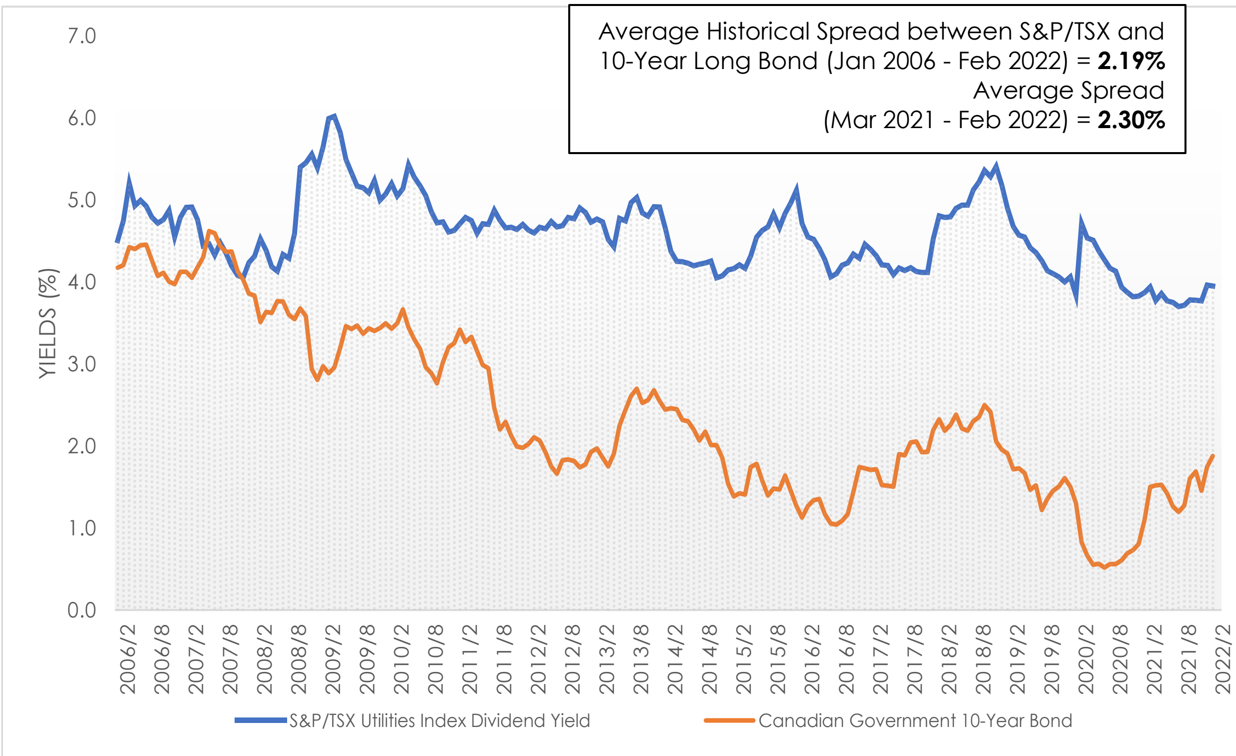
Figure 14: TSX Utilities Index vs. 30-year Canadian Gov't Bond Yield[31]



Another aspect of this relationship is observed with utility dividend yields, which historically have exhibited a high degree of correlation with government bond yields. However, since the Great Recession in 2008-2009 they have diverged. This trend is illustrated in Figure 15. The average spread between the S&P/TSX Utilities Index dividend yield and the 10-year Government of Canada bond yield was 2.30 percent from March 2021 through February 2022, compared with the long-term average of 2.19 percent between January 2006 and February 2022 and 2.87 percent in November 2018 when Maritime Electric filed evidence in the 2018 GRA. One interpretation is that investors are expecting higher government bond yields in the future, so rather than take the risk of rising interest rates diminishing the value of government bonds, they are favoring dividend-paying stocks such as utilities as a substitute. Another interpretation is that investors understand that government bond yields are responding to unique circumstances, and actions of the central banks and are not indicative of the risks of utility investments. Either way, the path of government bond yields is not indicative of the cost of equity for equity investors.

[31] Bloomberg Professional as of February 28, 2022.

Figure 15: S&P/TSX Utilities Index Dividend Yield vs. 10-Year GOC Bond Yields[32]



While not a perfect substitute due to the low interest rate environment, investors seeking an alternative to the low yields on government bonds have been purchasing the stocks of dividend-paying companies such as utilities. This has caused the valuations of utility stocks in both Canada and the U.S. to increase rather substantially since 2009. However, according to industry analysts such as Value Line, these high valuations are not expected to continue, as Price-to-Earnings ("P/E") ratios are projected to decline from current levels in the period from 2023-2027.

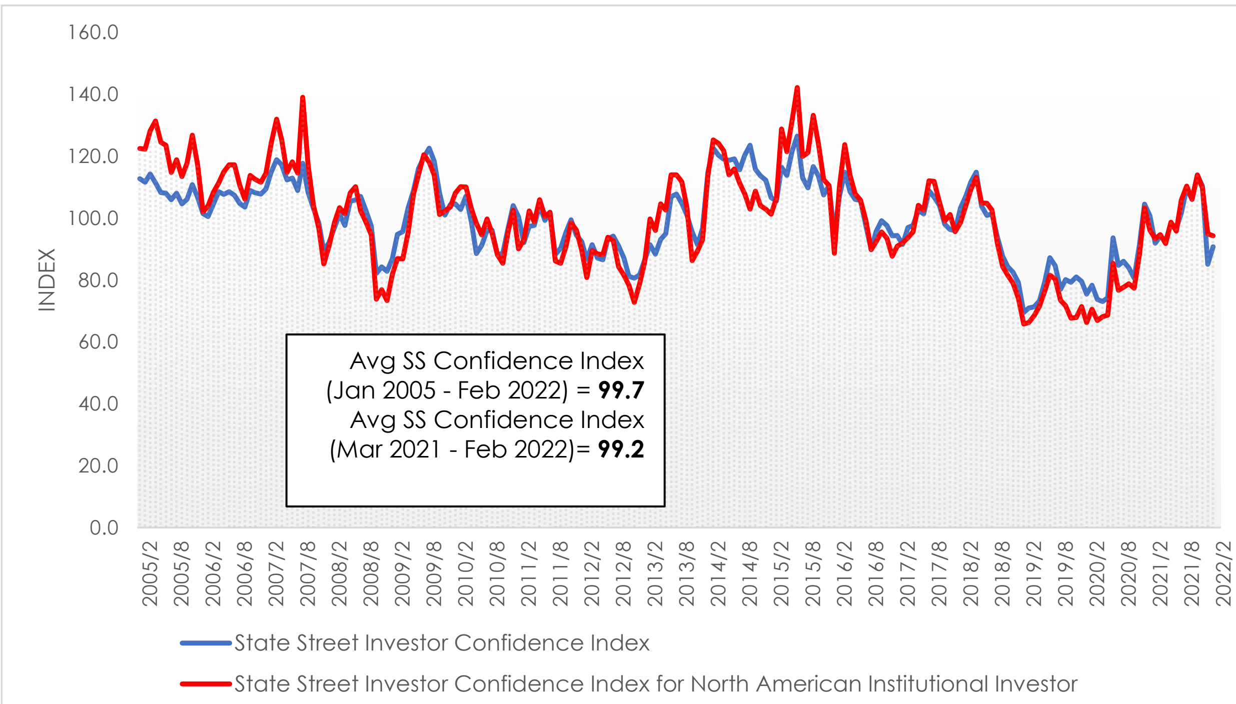
5. Investor Confidence

The investor confidence index, published by State Street Bank in the U.S., provides a quantitative measure of global risk tolerance. The index assesses investor confidence by reviewing the risk of investor portfolio investments. Figure 16 shows that investor confidence in 2020 was generally lower than during the global economic crisis of 2008-2009. After peaking in May 2018 at 114.80, investor confidence turned sharply lower and remained below 100 in all but two months from September 2018 through July 2021. From August through December 2021, investor sentiment

32 Bloomberg Series STUTILX and GCAN10YR as of February 28, 2022.

improved with the State Street index over 100 each month. However, in January and February 2022, the index has been between 85 and 91, which is well below than the long-term average of 99.7 but similar to its 84.3 level in November 2018 when Maritime Electric filed its evidence in the last GRA. This indicator's path thus far in 2022 highlights investors' concern with elevated inflation and geopolitical risk.

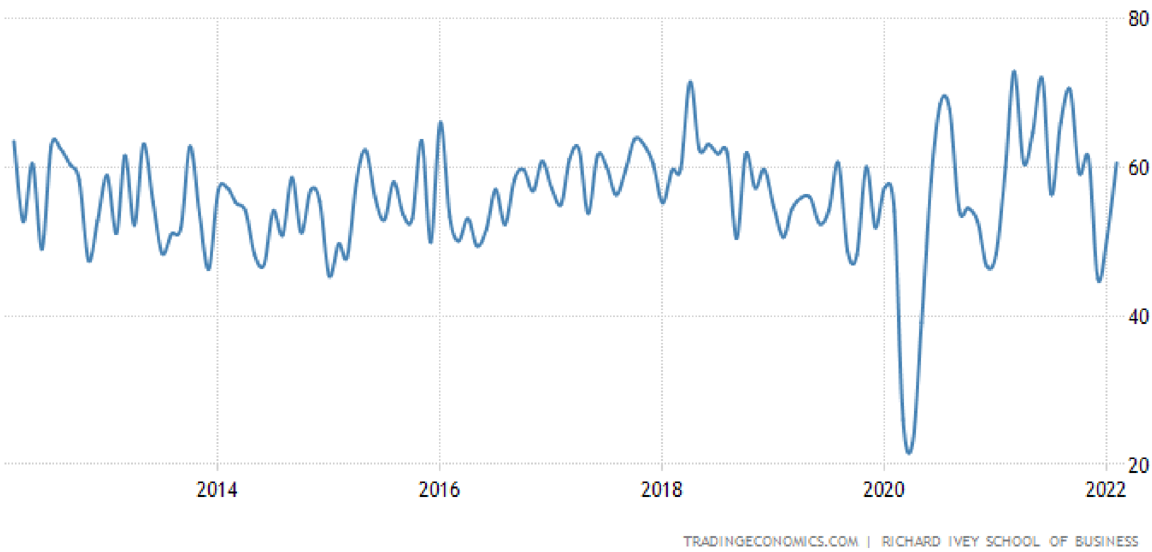
Figure 16: State Street Investor Confidence Indices[33]



While not an exact parallel, in Canada the Ivey School of Business publishes a monthly Purchasing Managers Index that measures business confidence. The Index stood at 60.6 in February 2022, which is near the long-term median for the last ten years, as shown in Figure 17. The Index measures price levels, supplier deliveries, job creation and inventories.

[33] Bloomberg SSICCONF Index and SSICAMER Index as of February 28, 2022.

Figure 17: Canadian Business Confidence Index[34]



E. Integration of Canadian and U.S. Capital Markets

In a world of increasingly linked economies and capital markets, investors seek returns from a global basket of investment options. Investors distinguish between risks on a country-to-country basis, factoring in the comparability of the economic, business and political environments.

Country-specific economic, business and political conditions that affect investment risk can be measured through a variety of qualitative and quantitative metrics. One such measure, produced by The Economist Intelligence Unit, rates Canada and the U.S. precisely the same from an overall country risk perspective (i.e., A) with AAA being the highest rating.[35] The Economist provides the following description of its country risk ratings:

> The Economist Intelligence Unit's Country Risk Service produces reports on 100 emerging markets and 20 OECD countries. These country-specific reports are complemented by this Risk ratings review, which analyses regional and global risk trends. The main focus of the ratings is on three risk categories to which clients can have direct exposure: sovereign risk, currency risk and banking sector risk. We also publish ratings for political risk and economic structure risk, as well as an overall country credit rating. The ratings are measured on a scale of 0-100. Higher scores indicate a higher level of risk. The

34 https://tradingeconomics.com/canada/business-confidence .
35 The Economist Intelligence Unit, Country Risk Service, Risk Ratings Review, August 2021, at 30.

scale is divided into ten overlapping bands: AAA, AA, A, BBB, BB, B, CCC, CC, C, D. In the Risk ratings review, ratings for a region are defined as the unweighted average of the ratings for all the countries being assessed in that region.[36]

Figure 18 summarizes the country risk ratings for Canada and the U.S. as of August 2021.

Figure 18: Country Risk Ratings

	Canada	**U.S.**
Sovereign Risk Rating	A	AA
Currency Risk Rating	A	A
Banking Sector Risk Rating	AA	A
Political Risk Rating	AAA	AA
Economic Structure Risk Rating	A	A
Overall Country Risk Rating	A	A

This suggests that from a country risk perspective, Canada and the U.S. are highly comparable in a global context. The Bank of Canada reflects this view with its own policy analysis where it finds: "The small open nature of the Canadian economy implies that its neutral rate is linked with the global neutral rate, which the Bank proxies using an estimate of the US neutral rate."[37]

The magnitude and significance of trade between the two countries reflects the high degree of integration between the two economies. According to the U.S. Department of State: "The United States and Canada enjoy the world's most comprehensive trading relationship, which supports millions of jobs in each country. Canada and the U.S. are each other's largest export markets, and Canada is the number one export market for more than 30 U.S. States."[38] Canada is currently the U.S.' 2nd largest goods trading partner overall with $525.7 billion in total (two way) goods trade during 2020.[39] This is an average two-way trade of US $1.4 billion per day, which increased to $1.8 billion per day during the first six months of 2021. This is an indication of the high degree of economic integration between the two economies.

36 Ibid, at 28.
37 Bank of Canada *Monetary Policy Report*, April 2022, p. 34. The neutral interest rate is an equilibrium interest rate that leads to GDP growing at its potential rate.
38 U.S. Department of State, https://www.state.gov/u-s-relations-with-canada .
39 https://www.census.gov/foreign-trade/balance/c1220.html .

Exhibit JMC-2 presents several measures that reflect the overall economic and investment environment in Canada and the U.S. On balance, the economic and business environments of Canada and the U.S. are highly integrated and exhibit strong correlation across a variety of metrics, including GDP growth and government bond yields. From a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely when compared against other developed and developing countries. Based on these macroeconomic indicators, there are no fundamental dissimilarities between Canada and the U.S. (in terms of economic growth, inflation, or government bond yields) that would cause a reasonable investor to have a materially different return expectation for a group of comparable risk utilities in the two countries. Our cost of capital analysis is framed by the conclusion that Canada and the U.S. have comparable macroeconomic and investment environments. We therefore consider both Canadian and U.S. proxy companies for our analysis.

F. Capital Market Conclusions

Although interest rates on government and corporate bonds have declined in recent years, that does not necessarily suggest that the cost of equity has declined. On the contrary, other risk factors indicate that the uncertainty and volatility in financial markets have caused equity investors to require a higher rate of return to compensate them for the additional uncertainty and risk created by the COVID-19 pandemic and the corresponding economic fallout. Longer term, the utility industry faces complex structural challenges associated with climate change, decarbonization, cyber security, grid modernization and shifting consumer preferences amid a flat overall consumption profile.[40] In addition, interest rates in both Canada and the U.S. are projected to increase from current levels over the next two to three years, as shown by the Consensus Economics forecasts, as inflation pressures mount and central banks shift monetary policy to a more neutral stance after a period of extraordinary accommodation.

[40] Maritime Electric is forecasting modest sales growth over the three year rate period, with a sales decline of 0.4% in 2023, followed by sales growth of 1.5% in 2024 and 1.3% in 2025.

IV. SELECTION OF PROXY COMPANIES

Since ROE is a market-based concept and given that Maritime Electric is not publicly-traded, it is necessary to establish a group of companies that is both publicly-traded and comparable to Maritime Electric's business and financial risk characteristics to serve as its "proxy" for purposes of estimating the cost of equity. Even if Maritime Electric's regulated electric utility operations made up the entirety of a publicly-traded entity, transitory events could bias that entity's market value in one way or another over a given period. A significant benefit of using a proxy group is that it mitigates the effects of company-specific events that may be transitory in nature. The proxy companies used in our ROE analyses each possess business and financial risk profiles similar to Maritime Electric's regulated electric utility operations, and thus provide a reasonable basis for the derivation and assessment of ROE and capital structure estimates.

Maritime Electric is a vertically-integrated electric utility that provides generation, transmission, and distribution service to approximately 84,000 residential, commercial, and industrial customers on Prince Edward Island. Maritime Electric has a long-term issuer rating from S&P of "BBB+" (Outlook: Stable). The Company issues First Mortgage Bonds and has a senior secured rating of "A" from S&P.

We developed three proxy groups for the ROE analysis. The first proxy group is comprised of publicly-traded, regulated Canadian electric and natural gas utility companies. Recognizing there are very few publicly-traded companies in the utility sector in Canada, the only screening criterion was an investment grade credit rating, which all companies in the sector have. Fortis, Inc. was excluded from the Canadian proxy group because it is the parent company of Maritime Electric. TransCanada was excluded due to the risk profile of the TransCanada Mainline, which arguably presents more risk than regulated electric utility operations. The following six companies comprise the Canadian proxy group:

Figure 19: Canadian Proxy Group

Company	*Ticker*
Algonquin Power and Utilities Corp.	AQN
AltaGas Ltd.	ALA
Canadian Utilities Limited	CU
Emera, Inc.	EMA
Enbridge, Inc.	ENB
Hydro One Ltd.	H

The development of a proxy group comprised entirely of Canadian electric utilities is challenged by the small number of publicly-traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of revenues and net income from operations other than regulated electric utility service. The continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility holding companies, further blurs the distinction between a Canadian and U.S. utility company. Therefore, Canadian regulators have adopted a pragmatic view of the use of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities.

Our second proxy group is comprised of U.S. electric utility companies that investors would consider as generally comparable in risk to Maritime Electric. To obtain companies of comparable risk, we applied a number of screens to develop a group of companies that is primarily engaged in the provision of regulated electric utility service. Starting with the 36 U.S. companies that Value Line classifies as Electric Utilities, we screened for companies that meet the following criteria:

a) Credit ratings of at least BBB from S&P or Baa2 from Moody's;

b) Consistently pay quarterly cash dividends, with no recent reductions or omissions of the dividend payment;

c) Positive earnings growth rate forecasts from at least two sources;

d) At least 70 percent of operating income derived from regulated operations in the period from 2018-2020;

e) At least 90 percent of regulated operating income derived from electric utility service in the period from 2018-2020; and

f) Not involved in a merger or other significant transformative transaction during the evaluation period.

The following ten U.S. electric utility companies met these screening criteria:

Figure 20: U.S. Electric Proxy Group

Company	*Ticker*
ALLETE, Inc.	ALE
Alliant Energy Corp.	LNT
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corp.	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy Inc.	NEE
OGE Energy Corporation	OGE
Portland General Electric Company	POR

The third proxy group is comprised of all ten U.S. electric utilities in Figure 20 plus the four Canadian investor-owned utilities that are primarily engaged in the provision of electricity (Algonquin Power & Utilities Corp, Canadian Utilities Limited, Emera and Hydro One). This group is referred to as the North American Electric proxy group shown in Figure 21.

Figure 21: North American Electric Proxy Group

Company	*Ticker*
Algonquin Power and Utilities Company	AQN
Canadian Utilities Ltd.	CU
Emera, Inc.	EMA
Hydro One Ltd	H
ALLETE, Inc.	ALE
Alliant Energy Corp.	LNT
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corp.	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy Inc.	NEE
OGE Energy Corporation	OGE
Portland General Electric Company	POR

Exhibit JMC-3 provides additional details on the proxy group screening process.

We have selected these groups of electric utilities to best align with the financial and operational characteristics of Maritime Electric. The proxy group screening criterion requiring an investment grade credit rating ensures that the proxy group companies, like Maritime Electric, are in sound financial condition. Because credit ratings take into account business and financial risks, the ratings provide a broad measure of investment risk for investors.[41] Additionally, we have screened our U.S. proxy group on the percent of net operating income from regulated operations to differentiate between utilities that are protected by regulation and those with substantial unregulated operations or market-related risks. Also, we have screened the U.S. proxy group on the percentage contribution of the electric utility segment to regulated consolidated financial results to select companies that, like Maritime Electric, derive the majority of their operating income from regulated electric operations. These screens collectively reflect key risk factors that investors consider in making investments in electric utilities. Our conclusion is that our proxy groups adequately reflect the broad set of risks that investors consider when investing in

41 Credit ratings are commonly used as screens for companies of comparable business and financial risks in cost of capital analysis in regulatory proceedings. Credit ratings are exclusively focused on the risks for debt investors, but do not account for the risks for equity investors.

regulated electric utility companies such as Maritime Electric. Later in the report, we conduct more detailed risk analysis to determine if any adjustments are required to account for risks specific to Maritime Electric.

V. METHODS FOR ESTIMATING THE COST OF EQUITY

A. Financial Models to Estimate the Cost of Equity

Multiple approaches have been developed to estimate the cost of common equity. These financial models rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Quantitative models produce a range of results from which the market-required cost of equity is determined. The methodologies used to estimate the cost of common equity should reflect investors' forward-looking views of financial markets in general, and the risk profile of the subject company relative to the proxy group in particular.

No financial model can exactly pinpoint the correct return on equity. Rather, each model brings its own perspective and set of inputs and assumptions that inform the estimate of the ROE. Consistent with the *Hope* standard, it is "the result reached, not the method employed, which is controlling."[42] Although each model brings a different perspective and adds depth to the analysis, each model also has its own inherent weaknesses and should not be relied upon individually without corroboration from other approaches. Regardless of which analyses are used to estimate the investor's required cost of equity, the analyst must apply informed judgment to assess the reasonableness of results and to determine the appropriate weight to apply to results under current and prospective capital market conditions.

1. Discounted Cash Flow ("DCF") Model

The premise underlying the DCF model is that investors value a given investment according to the present value of its expected future cash flows over time. The standard DCF model is shown in Formula [1]:

$$P = \frac{D_0(1+g)^1}{(1+r)^1} + \frac{D_1(1+g)^2}{(1+r)^2} + \cdots + \frac{D_{n-1}(1+g)^n}{(1+r)^n} \qquad [1]$$

where:

P = the current stock price

g = the dividend growth rate

[42] *See* Hope Natural Gas v. Federal Power Commission.

D_n = the dividend in year n

r = the cost of common equity.

Assuming a constant growth rate in dividends, the model may be rearranged to compute the ROE, as shown in Formula [2]:

$$r = \frac{D}{P} + g \quad [2]$$

Stated otherwise, the cost of common equity is equal to the dividend yield plus the expected dividend growth rate.

a. Constant Growth DCF Model Assumptions

The Constant Growth DCF model requires the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. The assumptions of the Constant Growth DCF model are generally reasonable for regulated utility companies, which operate in a stable and mature industry and are characterized by a relatively steady state of earnings and dividend growth.

b. Dividend Yield

As shown in equation [3], the dividend yield component of the DCF model is calculated as follows:

$$[3] \quad Y = \frac{D_0(1+0.5g)^1}{P_0}$$

One half year's growth rate is applied to the annual dividend rate to account for increases in quarterly dividends at different times throughout the year. It is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. This adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period and does not overstate the aggregated dividends to be paid during that time.

The dividend yields were calculated for each company in the respective proxy groups by dividing the current annualized dividend by the average stock price for each company for the 90-trading days ended February 28, 2022. Those dividend yields are multiplied by one-half the growth rate to reflect expected future dividend increases.

c. Growth Rate Estimates

In considering the appropriate growth rate for the DCF model, the projected earnings per share growth rate from equity analysts is the most reliable indicator of investors' expectations. We have relied on consensus earnings growth rate estimates from Zacks Investment Research, Thomson First Call, and SNL Financial and earnings growth rate estimates from Value Line for the companies in the respective groups. Those growth rates are shown in Exhibit JMC-4.

Investors typically rely on projected earnings growth rates rather than dividend growth rates for several reasons. First, although the DCF model is based on the expected growth rate for dividends, a company's dividend growth is derived from and can only be sustained by earnings growth. Second, in order to reduce the long-term growth rate to a single measure, as required in the Constant Growth DCF model, it is necessary to assume a constant payout ratio, and that earnings per share, dividends per share and book value per share grow at a constant rate. Third, earnings growth rates are less influenced by dividend decisions that companies may make in response to near-term changes in the business environment. Finally, analysts' earnings growth forecasts are widely available, whereas dividend and book value growth rates are generally available only from Value Line.[43]

Some utility regulators in Canada have expressed concern that analysts' earnings growth rates may be overly optimistic. If optimism bias were present in analysts' earnings forecasts, it could create an upward bias in the estimated cost of capital that results from the DCF approach. However, financial regulators implemented several changes approximately 20 years ago that were designed to provide fair disclosure and to reduce or eliminate the possibility of analysts' bias. For example, on August 15, 2000, the U.S. Securities and Exchange Commission ("SEC") adopted Regulation FD to address the selective disclosure of information by publicly-traded companies. Regulation FD provides that when an issuer discloses material nonpublic

[43] Value Line is the only publication of which I am aware that projects dividend and book value growth rates. Those estimates represent the Value Line analyst's perspective on dividend and book value growth. In contrast, many of the earnings growth rates that are publicly available are consensus estimates with contributions provided by several analysts.

information, the issuer must publicly disclose that information to all investors at the same time. In this way, the rule aims to promote full and fair disclosure.

Also, in 2002 the SEC, the New York Stock Exchange, the New York Attorney General, and other state regulators introduced guidelines regarding the interaction between analysts and investment banks that became known as the "Global Settlement." The Global Settlement outlined several structural reforms that limit the interaction between analysts and investment banks, thus removing any incentive for analysts to produce upwardly-biased growth forecasts.

In Canada, regulators took a parallel set of actions, with Policy 11 as the core framework. On April 12, 2001, the Securities Industry Committee on Analyst Standards released a draft report containing recommendations aimed at improving the independence of research and ensuring the professional practice of Canadian securities industry analysts. The Investment Dealers Association published the initial proposed Policy 11 on July 5, 2002, a revised version on April 25, 2003, and a summary of comments on August 8, 2003. Policy 11 requires more disclosures from analysts and independence of research departments. Also, in a letter dated August 15, 2002, the Ontario Securities Commission ("OSC") requested information from financial institutions about current practices to address conflicts of interest relating to equity analysts. Accordingly, in September 2002, most financial institutions had adjusted their practice and replied to OSC.

After these new policies were enacted by securities regulators in the U.S. and Canada, a 2010 article published in Financial Analysts Journal found that analyst forecast bias had declined significantly or disappeared entirely:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[44]

[44] Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010, at 105.

In order to assess whether earnings growth rates are reasonable relative to GDP growth, which is sometimes offered as a check on analyst earnings growth projections, we compared the actual earnings and dividends per share growth rates for the companies in the three proxy groups for which the required data are available to GDP growth. These results are shown in Figure 22.

Figure 22: Utility Earnings, Dividend and GDP Growth Comparisons

	[1]	[2]	[3]	[4]	[5]
	Average EPS Growth Historical 2005-2019	**Average DPS Growth Historical 2005-2019**	**CAGR GDP Growth 2005-2019**	**Average EPS Growth Forecast 2021-2024**	**Nominal GDP Growth Forecast**
Canadian Proxy Group	7.77%	10.24%	3.96%	6.73%	3.84%
U.S. Electric Proxy Group	4.77%	4.82%	3.59%	5.65%	4.35%
North American Electric Proxy Group	4.99%	5.13%	3.65%	5.73%	4.20%
Average	5.84%	6.73%	3.74%	6.04%	4.13%

[1] Value Line, median compound annual growth rate in EPS of each company the proxy group
[2] Value Line, median compound annual growth rate in DPS of each company the proxy group
[3] Statistics Canada, Table: 36-10-0104-01 (formerly CANSIM 380-0064)
Bureau of Economic Analysis, Table 1.1.5. Gross Domestic Product, Accessed on January 19, 2022
Combined Proxy Group number is weighted average of Canadian and US results
[4] See Exhibit JMC-4 Constant DCF
[5] See Exhibit JMC-5 Multi-Stage DCF

This analysis shows important relationships based on fifteen years of history, which is a sufficient time-period to draw meaningful conclusions and to frame reasonable investor expectations for the future.[45]

1) Dividends track reasonably well with earnings growth, as would be expected, as earnings drive dividend growth. The exception is the Canadian proxy group, where dividends outpaced earnings growth over this period. This is primarily due to Enbridge, which had a significant increase in its payout ratio. I conclude that earnings growth is a reasonable proxy for dividend growth, especially with a broad enough company sample.
2) Both earnings and dividend growth exceeded GDP growth by a wide margin from 2005-2019, with the exception of DPS growth for the U.S. Electric proxy group, where

45 2020 Value Line data was excluded from this analysis because several of the companies had very low EPS in 2020 due to the effects of COVID-19 on their sales and revenues.

dividend growth only slightly exceeded GDP growth. This should not be a surprise, as earnings for a healthy and well-managed utility can exceed the growth of the overall economy. There is no fundamental basis to assume that economy-wide GDP growth with a mix of macroeconomic, social, and business drivers serves as a limit on utility earnings growth.

3) Looking to the future, it is not unreasonable to rely on analyst projections, as we and other experts commonly do, just because they exceed GDP growth. In fact, over the historical period, average dividend growth for the three utility proxy groups exceeded historical GDP growth by 2.99 percent. Further, the average analyst earnings growth projection of 6.04 percent is generally consistent with the historical earnings growth rate of 5.84 percent.

These relationships indicate the projected analyst growth rates are entirely reasonable by historical standards.

2. Multi-Stage DCF Model

In order to address some of the limiting assumptions underlying the Constant Growth form of the DCF model, we also considered the results of a multi-period (three-stage) DCF Model. The Multi-stage DCF model tempers the assumption of constant growth in perpetuity with a three-stage approach based on near-term, transitional, and long-term growth rates.

The Multi-stage DCF model transitions from near-term growth (i.e. the average of Zacks, First Call, SNL Financial and Value Line forecasts used in the Constant Growth model) for the first stage (years 1-5) to the long-term forecast of nominal GDP growth for the third stage (year 11 and beyond). The second, or transitional, stage connects near-term growth with long-term growth by changing the growth rate each year on a pro rata basis. In the terminal stage, the dividend cash flow then grows in perpetuity at the same rate as nominal GDP (or a total of 200 years). The return on equity is the internal rate of return based on the current average stock price and this stream of dividend payments. As we have shown above, projected GDP growth is conservative based on the historic earnings and dividend growth of the proxy group companies.

Nominal GDP growth rates for the proxy groups were developed using data for each country as reported by Consensus Economics for the period from 2027-2031. These forecasts are based on real (constant dollar) growth rates and estimates for inflation. The inflation estimate was applied to the estimate of real GDP growth to develop the nominal (post-inflation) GDP growth rate. The estimates of nominal GDP growth are summarized in Figure 23.

Figure 23: Nominal GDP Growth Forecasts – 2027-2031[46]

	Canada	U.S.
Real GDP Growth	1.8%	2.0%
Inflation	2.0%	2.3%
Nominal GDP Growth	3.84%	4.35%

3. DCF Results

The DCF results are shown in Figure 24 and in Exhibits JMC-4 and JMC-5. As summarized in Figure 24, the DCF analyses produce an average cost of common equity of 11.3 percent for the Canadian Utility proxy group, 9.4 percent for the U.S. Electric proxy group, and 9.7 percent for the North American Electric Utility proxy group, including an adjustment for flotation costs and financial flexibility.

Figure 24: 90-day Average DCF Results (including flotation costs)

Proxy Group	Constant Growth	Multi-Stage	Average
Canadian Utility	12.08%	10.48%	11.3%
U.S. Electric Utility	9.77%	8.96%	9.4%
North American Electric Utility	10.12%	9.21%	9.7%

The DCF results for the U.S. Electric Utility proxy group and the North American Electric Utility proxy group are both significantly lower than the DCF results for the Canadian proxy group. As discussed in more detail in Section VI, the U.S. Electric utility proxy group is more comparable to

[46] Consensus Forecasts, for 2027-2031, October 12, 2021, at 3 (U.S.) and 28 (Canada).

Maritime Electric than the Canadian utility proxy group companies, many of which have significant non-electric operations and unregulated operations. Conversely, the U.S. Electric utility proxy group is comprised of companies that derive almost 100 percent of net operating income and operating revenues from electric utility operations, and dedicate almost 100 percent of assets to regulated electric utility service. This proxy group therefore addresses concerns regarding the comparability of these companies to the target company, Maritime Electric, from an investment perspective.

4. Capital Asset Pricing Model ("CAPM")

The CAPM approach is based on the relationship between the required return of a security and the systematic risk of that security. As shown in Equation [4], the CAPM is defined by four components, each of which must be a forward-looking estimate:

[4] $Ke = rf + \beta(rm - rf)$

where:

Ke = the required ROE for a given security;

β = Beta of an individual security;

rf = the risk-free rate of return; and

rm = the required return for the market as a whole.

The term (rm – rf) represents the Market Risk Premium ("MRP").

According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

[5] $$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)}$$

where:

r_e = the rate of return for the individual security or portfolio.

The variance of the market return, noted in Equation [5], is a measure of the variability in the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, Beta represents the risk of the security relative to the market.

a. Risk Free Rate

Although government bond yields have increased in recent months as central banks in both Canada and the U.S. have signaled a tightening of monetary policy, these yields remain well below the historical average. At the same time, investors expect that interest rates will continue to increase over the near to intermediate term. It is therefore particularly important to reflect forward-looking expectations for government bond yields. The use of forecast bond yields, as opposed to the current risk-free rate, reflects the current market reality that while bond yields remain lower than the long-term average, investors are factoring higher interest rates into their longer-term expectations and required returns.

Our CAPM analysis relies on the 2023-2025 average *Consensus Economics* forecast yield of Canadian and U.S. 10-year government bonds (shown in Figure 25) plus the historical spread between 10-year and 30-year government debt.

Figure 25: Long-term Forecast for 10-Year Government Bond Yields[47]

	2023	2024	2025	Average
Canada	2.3%	2.6%	2.8%	**2.57%**
U.S.	2.6%	2.9%	3.1%	**2.87%**

With an average spread between 10-year and 30-year government bond yields of 27 basis points in Canada and 31 basis points in the U.S.,[48] the corresponding longer-term yield on 30-year government bonds over the period 2023–2025 is shown in Figure 26. These spreads have increased since August 2018 (when the analysis in Concentric's 2018 report was performed) when the Canadian spread was 1 basis point and the U.S. spread was 15 basis points.

47 Consensus Forecasts by Consensus Economics Inc., Survey Date October 12, 2021, at 28 and 3.
48 Historical spreads were calculated using daily bond yields for February 2022.

Figure 26: Risk Free Rate

30-Year Risk Free Yield	Canada	U.S.
October 2021 Consensus Forecast Average 2023-2025 Forecasts for 10-year government bonds	2.57%	2.87%
Average Daily Spread between 10-year and 30-year government bonds (February 2022)	0.27%	0.31%
Sum	**2.84%**	**3.18%**

b. Beta

The Beta coefficients for the companies in the proxy groups are based on estimates from Value Line and Bloomberg.[49] Value Line publishes Beta estimates for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index. Bloomberg produces Beta estimates based on parameters entered by the user. We computed Bloomberg Betas based on five years of weekly stock returns and used the S&P 500 (in the U.S) or the S&P/TSX Composite (in Canada) as the market index. Both Value Line and Bloomberg report adjusted Betas to compensate for the tendency of Beta to revert toward the market average of 1.0 over time. The Betas used in our CAPM analyses are shown in Figure 27. It is important to note that Betas have increased substantially since 2018, and raw Betas for the proxy group companies in February 2022 are at levels similar to those of adjusted Betas in August 2018. This is further evidence that regulated utility companies are trading more like the overall market, not like the safe havens they have been known as in the past.

Figure 27: Value Line and Bloomberg Betas

	Value Line	***Bloomberg***
Canadian Group	0.83	0.89
U.S. Electric Group	0.92	0.89
North American Electric Group	0.90	0.87

There are two primary reasons to adjust raw Betas. First, numerous empirical studies have demonstrated that an individual company Beta is more likely than not to move toward the market average of 1.0 over time. Second, adjusting Beta serves a statistical purpose. Because Betas are statistically estimated and have associated error terms, Betas greater than 1.0 tend to have positive estimated errors and thus tend to overestimate future returns. Conversely, Betas below

49 We have used Bloomberg betas for the Canadian proxy group and both Value Line and Bloomberg betas for the U.S. proxy group.

the market average of 1.0 tend to have negative error terms and underestimate future returns. Consequently, it is necessary to adjust forecasted Betas toward 1.0 in an effort to improve forecasts.[50] A raw Beta reflects only where the stock price has been relative to the market historically and is an inferior proxy for the expected returns when compared to the adjusted beta.

The Betas in our analysis are also supported by a study conducted for the British Columbia Utilities Commission by the Brattle Group on cost of capital methodologies, in which Brattle observed:

> Beta estimates are provided by many data services for Canadian, American and other traded companies. The most common methodology to estimate betas is to use the most recent five years of weekly or monthly return data. These betas may then be adjusted towards one as an adjustment for sampling reversion that was first identified by Professor Marshall Blume (1971, 1975).[51]

Dr. Blume specifically studied four groups of betas, ranging from a very low Beta group to a very high Beta group, and found that his adjustment best predicted future Betas for each of the four risk groups over the next seven years. Dr. Blume found that a low Beta portfolio that averaged 0.50 migrated towards the grand mean of all Betas of 1.0 approximately in accordance with the Blume formula. The study makes obvious that Betas migrate towards 1.0 and do indeed exceed their long-term unadjusted averages. Given that the CAPM is intended to estimate the forward-looking cost of capital, it is important to reflect a forward view of Beta and its tendency to revert toward the market mean over time.

c. Market Risk Premium

Estimates of the MRP generally fall into two categories, *ex-post* (historical arithmetic average) and *ex-ante* (forward looking). The historical MRP is based on the arithmetic mean of the equity market returns over the income only return on long-term government bonds, based on data from Duff & Phelps. In Canada, the historical MRP is based on return data from 1919-2020, while in the U.S., the historical MRP is calculated using return data from 1926-2020. The forward-looking MRP is calculated by subtracting the risk-free rate for each country from the estimated total return for the overall market, as calculated using the DCF methodology for the S&P/TSX

50 Roger A. Morin, *New Regulatory Finance*, at 74.
51 The Brattle Group (May 31, 2012) – Survey of Cost of Capital Practices in Canada, at 15.

Composite Index in Canada and the S&P 500 Index in the U.S. This is consistent with FERC's approach to estimating the market equity risk premium for electric transmission companies.

Because the U.S. and Canadian economies are highly integrated and capital flows freely across the border, the risk premiums for each country are highly correlated. Accordingly, it is reasonable to derive a single forward-looking estimate of the MRP for Canada and the U.S., as provided in Figure 28. Exhibits JMC-6 and JMC-7 show the derivation of the forward-looking MRP for Canada and the U.S.

Figure 28: Market Risk Premium Values

	Canadian MRP	U.S. MRP
Historical MRP	5.54%	7.25%
Forward-looking MRP	8.40%	10.26%
Average	**7.86%**	

Forward-looking MRPs currently are about 300 basis points higher than historical MRPs, reflecting the fact that the historical MRP is based on much higher government bond yields than are available in the current low interest rate environment. Because there is an inverse relationship between interest rates and the MRP, meaning that as interest rates increase (decrease), the MRP decreases (increases), historical MRPs would underestimate the forward-looking MRP in the current low bond yield environment. Underscoring the importance of this point, the average 30-year bond yield over the course of the historical period that these MRPs were calculated was approximately 5.6 percent in Canada and 4.9 percent in the U.S., in contrast to the currently projected 2.8 - 3.2 percent bond yields today. In order to be consistent with our approach elsewhere in Canada, we have used an average of the historical and forward-looking MRP; however, given the low interest rate environment, it would be reasonable to place more reliance on a forward-looking MRP in the CAPM analysis.

d. CAPM Results

The results of the CAPM analysis, including flotation costs, are shown in Figure 29 and in Exhibits JMC-8.1 and 8.2.

Figure 29: CAPM Results (including flotation costs)

	Average MRP	Forward-looking MRP
Canadian	10.35%	11.66%
U.S. Electric Utilities	10.79%	12.12%
North American Electric	10.48%	11.77%

5. Flotation Costs and Financing Flexibility

It is common practice for Canadian regulators to allow an adjustment for flotation costs and financing flexibility in order to compensate the equity holder for the costs associated with the sale of new issues of common equity. These costs include out-of-pocket expenditures for the preparation, filing, underwriting and other costs of issuance of common equity including the costs of financial flexibility such that there is adequate cushion to raise equity in a variety of capital market conditions. Because the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital the regulated company would incur to raise money in the "primary" markets, an estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost of capital that the regulated company requires. We have adjusted the DCF and CAPM results upwards by 50 basis points for flotation costs and financing flexibility. This is consistent with the 2019 Commission order (Order UE19-08) authorizing an ROE of 9.35 percent for Maritime Electric, which implicitly included 50 basis points for flotation costs and financing flexibility.

6. Risk Premium Analysis

In general terms, the Risk Premium approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (i.e., a premium) than would a bondholder. The Risk Premium approach estimates the cost of equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.

$$ROE = RP + Y \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROE and the 30-Year Treasury Yield) and

Y = Applicable bond yield.

Since the equity risk premium is not directly observable, it is typically estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking, estimates of the cost of equity and others that consider historical, or ex-post, estimates. For our Risk Premium analysis, we have relied on authorized returns from a large sample of U.S. electric utility companies. It is necessary to conduct the Risk Premium analysis based on authorized returns for U.S. electric utility companies because there are not a sufficient number of Canadian ROE decisions to develop a statistically-meaningful regression analysis.

To estimate the relationship between risk premia and interest rates, we conducted a regression analysis using the following equation:

$RP = a + (b \times Y)$ [7]

Where:

RP = Risk Premium (difference between allowed ROEs and the 30-Year Treasury Yield);

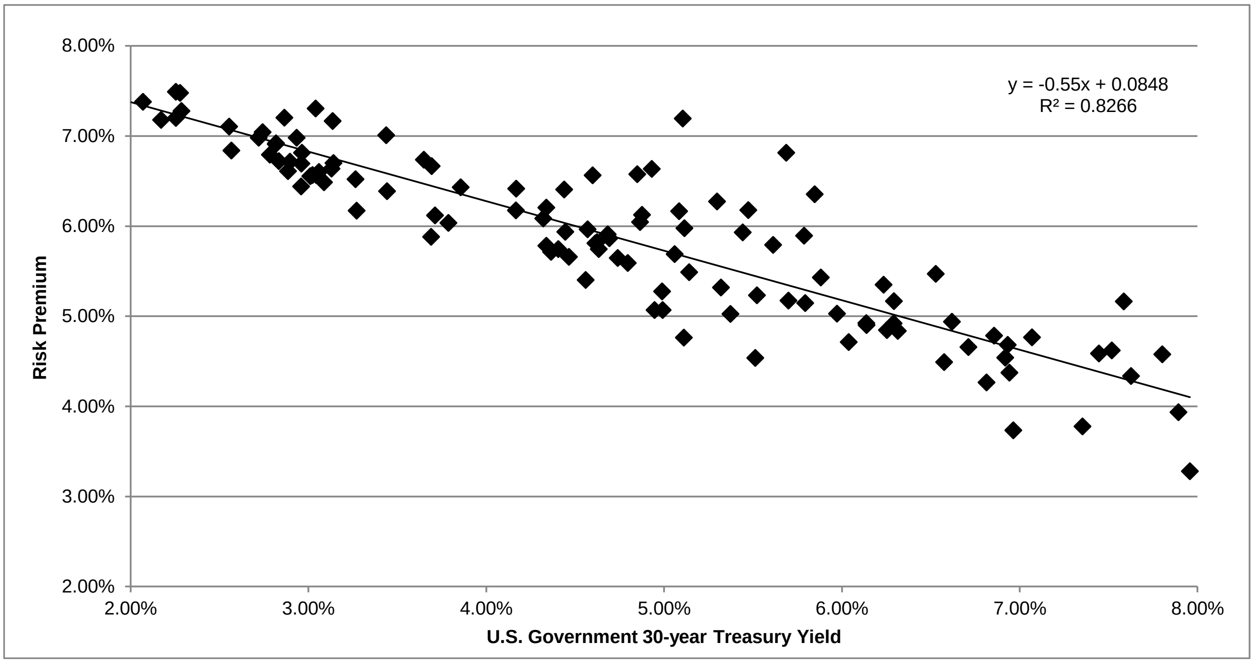
a = Intercept term;

b = Slope term; and

Y = 30-Year Treasury Yield.

Data regarding allowed ROEs were derived from 859 electric utility company rate cases in the U.S. from January 1992 through February 28, 2022, as reported by Regulatory Research Associates.

Figure 30: Risk Premium Results



As illustrated by Figure 31, the risk premium varies with the level of the bond yield, and generally increases as the bond yields decrease, and vice versa. In order to apply this relationship to current and expected bond yields, we consider three estimates of the 30-year Treasury yield, including the current 30-day average, a near-term Blue Chip consensus forecast for Q2 2022 – Q2 2023, and a Blue Chip consensus forecast for 2023–2027. We find this 5-year result to be most applicable for the following reasons: (1) investors are expecting increases in government bond yields; and (2) investors typically have a multi-year view of their required returns on equity. Based on the regression coefficients in Exhibit JMC-9, which allow for the estimation of the risk premium at varying bond yields, the results of our Risk Premium analysis are summarized in Figure 31.

Figure 31: Risk Premium Results

	30-Day Average Yield on 30-Year Treasury Bond	Q2 2022–Q2 2023 Forecast for Yield on 30-Year Treasury Bond[52]	2023-2027 Forecast for Yield 30-Year Treasury Bond[53]
Yield	2.20%	2.74%	3.40%
Risk Premium	7.27%	6.97%	6.61%
Resulting ROE	9.47%	9.71%	10.01%

B. Comparison to Other Authorized ROEs

Investors consider authorized ROEs for other investor-owned electric utilities in Canada and the U.S. as a relevant benchmark for purposes of establishing their return expectations. Given the "opportunity cost" concept underlying a fair return, this is reasonable and appropriate because an investor would allocate capital to a higher return for the same level of risk, if available. As shown in Figure 32, the average authorized ROE for Canadian investor-owned electric utilities was 8.71 percent (2021) and 8.76 percent (2022), while in the U.S., the average authorized ROE for electric utilities in 2021 was 9.41 percent and the year-to-date average in 2022 (includes six decisions through February 28, 2022) is 9.34 percent.

52 Blue Chip Financial Forecasts, Vol. 41, No. 3, March 1, 2022, at 2.
53 Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14.

Figure 32: Authorized ROEs[54]

	2021 Allowed ROE	2022 Allowed ROE
Maritime Electric - current	9.35%	9.35%
Maritime Electric - proposed		9.95%
Canadian Electric Utilities		
Nova Scotia Power Inc.	9.00%	9.00%
Newfoundland Power Inc.	8.50%	8.50%
FortisOntario Inc.	8.34%	8.66%
Hydro One Networks, Inc. - Distribution	9.00%	9.00%
ATCO Electric Distribution	8.50%	8.50%
FortisAlberta Inc.	8.50%	8.50%
FortisBC Inc.	9.15%	9.15%
Average	**8.71%**	**8.76%**
U.S. Electric Utilities[55]	**9.41%**	**9.34%**

In particular, for other investor-owned electric utilities in the Atlantic Canada region, the current allowed ROE for Nova Scotia Power is 9.00 percent on 37.50 percent common equity, and for Newfoundland Power is 8.50 percent on 45.00 percent common equity. The Commission has previously considered this information relevant in setting the allowed ROE and equity ratio for Maritime Electric.[56]

The generation function is generally regarded by investors as having greater risk than electric transmission or distribution. In terms of relative generation risk, Maritime Electric has similar generation risk as Newfoundland Power, which purchases approximately 93 percent of its electricity supply from Newfoundland and Labrador Hydro while generating the remaining 7 percent from company-owned hydro-electric plants, primarily for peaking purposes. Nova Scotia

54 We have presented authorized returns for a sample of investor-owned electric utilities in Canada because these data are available at the operating company level. It is not possible to provide such data for the Canadian proxy group companies, all of which are holding companies.
55 Source: SNL Financial. Figures are from January 1, 2021 through March 25, 2022.
56 The Island Regulatory and Appeals Commission, Docket UE20940, Order UE10-03, July 12, 2010, at paragraph [101].

Power owns substantial generation assets and has higher generation risk than Maritime Electric. Maritime Electric is more risky than electric utilities in Ontario and Alberta because Maritime Electric owns generation assets, while electric utilities in those provinces do not. The Commission has previously accepted that Maritime Electric, with its responsibilities for electricity supply, is different than Ontario's electric distribution utilities, and the Commission has stated that it "views this difference as significant."[57] Furthermore, the Commission has stated that it "views Maritime Electric as higher risk than the benchmark BC utility and FortisBC due to a variety of factors such as utility size, nature of operations, economic climate within which it operates, and regulatory risk factors."[58]

Another important consideration is that Maritime Electric has a hard cap on its authorized ROE, with any earnings above that level returned to customers. By contrast, several investor-owned electric utility companies are allowed to earn above the authorized ROE either within a specified band or without any specific limitations. In addition, several of these companies also operate under performance based ratemaking programs that specifically allow for both upside and downside earnings risk. For example, Alberta's utilities can earn up to 500 basis points over their allowed return in a single year or 300 basis points for two consecutive years.[59] Ontario's electric distributors have a 300 basis point earnings deadband.[60] Fortis' two British Columbia utilities (FortisBC Energy Inc. ("FEI", the gas utility) and FortisBC Inc. ("FBC", the electric utility)) can earn up to 150 basis points over their allowed ROEs; those excess earnings are shared 50/50 with customers. An off-ramp is triggered if achieved earnings deviate from the authorized level by more than 150 basis points, either above or below the authorized ROE.[61] Newfoundland Power has an Excess Earnings Account that limits the Company's return on equity to approximately 40 to 50 basis points above the authorized return for ratemaking purposes. These are important considerations to equity investors. As shown in Figure 33, Maritime Electric has the lowest weighted equity return among these Canadian utilities on this basis.

57 *Id.*, at paragraph [99].
58 *Id.*, at paragraph [104].
59 See AUC Decision 2012-237, September 12, 2012, at para 737.
60 See Report of the Ontario Energy Board, Renewed Regulatory Framework for Electricity, October 18, 2012, at 13.
61 See BCUC Orders G-165-20 and G-166-20, June 22, 2020, at ii.

Figure 33: Weighted Equity Return Based on Upper Bound ROE

Utility	Authorized ROE	Deadband	Upper Bound ROE	Equity Ratio	Upper Bound Weighted ROE
Maritime Electric	9.35%	None	9.35%	40.0%	3.74%
Alberta Electric Utilities – one year	8.50%	5.00%	13.50%	37.0%	5.00%
Alberta Electric Utilities – two years	8.50%	3.00%	11.50%	37.0%	4.26%
Ontario Electric Utility Distributors	8.34%	3.00%	11.34%	40.0%	4.54%
FortisBC Energy Inc. (gas)	8.75%	1.50%	10.25%	38.5%	3.95%
FortisBC Inc. (electric)	9.15%	1.50%	10.65%	40.0%	4.26%
Newfoundland Power	8.50%	0.50%	9.00%	45.0%	4.05%

VI. RISK ASSESSMENT

Concentric examines risk from two primary perspectives: (1) business risk; and (2) financial risk. Business risk for a regulated utility encompasses both operational risk (e.g., economy of service territory, weather conditions, geographical diversity, and size of service territory, etc.) and regulatory risk (e.g., opportunity for timely recovery of prudently-incurred costs). Financial risk primarily relates to the risk associated with the way in which a company finances its business, as evidenced by the relative percentages of debt and equity in the capital structure. To the extent a company is more highly leveraged, it requires higher net income to cover its fixed interest obligations, which must be paid before there is any net income for shareholders. Taken together, business and financial risk are the primary elements of investment risk that investors consider when establishing their return requirements.

In each risk category, Concentric further considers three perspectives:

a) Assessment of the business risk profile of Maritime Electric based on the macroeconomic and business environment of its service area;

b) Comparison of the business risk profile of Maritime Electric against Canadian investor-owned electric utilities and the U.S. peer group; and

c) Comparison of the financial risk profile of Maritime Electric against these same comparators.

A. Business Risk of Maritime Electric

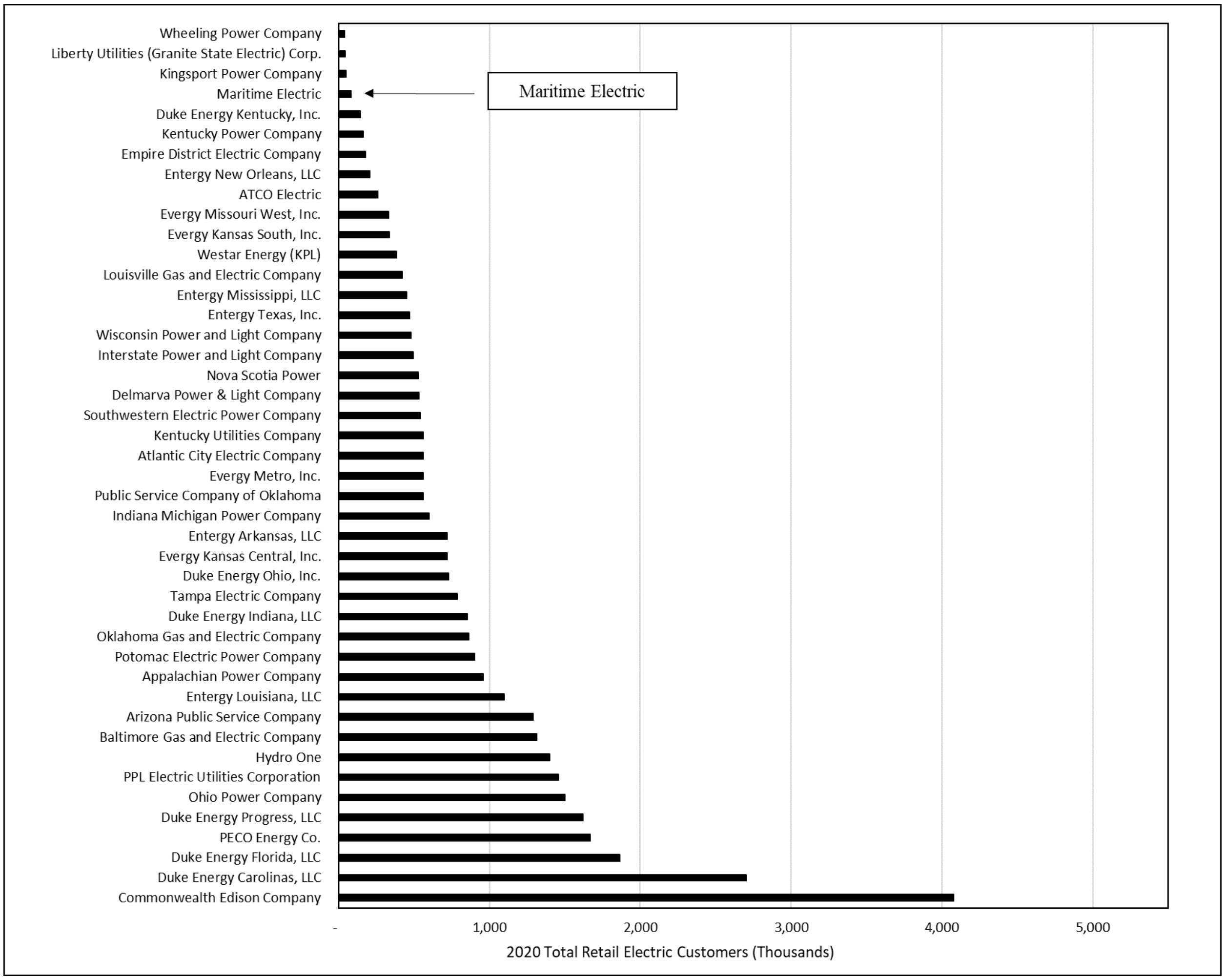
In order to assess the business risk of Maritime Electric, we considered the following factors: 1) the size of Maritime Electric relative to other electric utilities in Canada and the U.S.; 2) macroeconomic and demographic trends on Prince Edward Island, as well as Canada generally; 3) operating risks within the Company's service territory, including power supply risks and weather conditions; 4) deferral and variance accounts that protect the Company against risks from events that are material in nature and beyond the control of utility management; and 5) risks related to competition from alternative fuel sources.

1. Small Size

Maritime Electric is significantly smaller than other electric utilities in the Canadian and U.S. proxy groups, both in terms of retail electric customers and net property, plant and equipment, as shown in Figure 34 and Figure 35, which measure these metrics at the operating company level. The Commission has previously recognized that the small size of Maritime Electric makes the Company more risky than other electric utilities in Canada,[62] and this finding has been used to support an above average ROE. Nothing has changed in this regard since the Company's 2018 GRA filing. Further, effective January 1, 2017, the Electric Power Act requires Maritime Electric to maintain a common equity ratio of at least 35.0 percent but not to exceed 40.0 percent, which contributes to greater financial risk than its Canadian and U.S. peers. The small size of Maritime Electric supports an equity ratio higher than the upper limit of 40.0 percent allowed by the statute and/or an allowed ROE above the mean for the proxy groups.

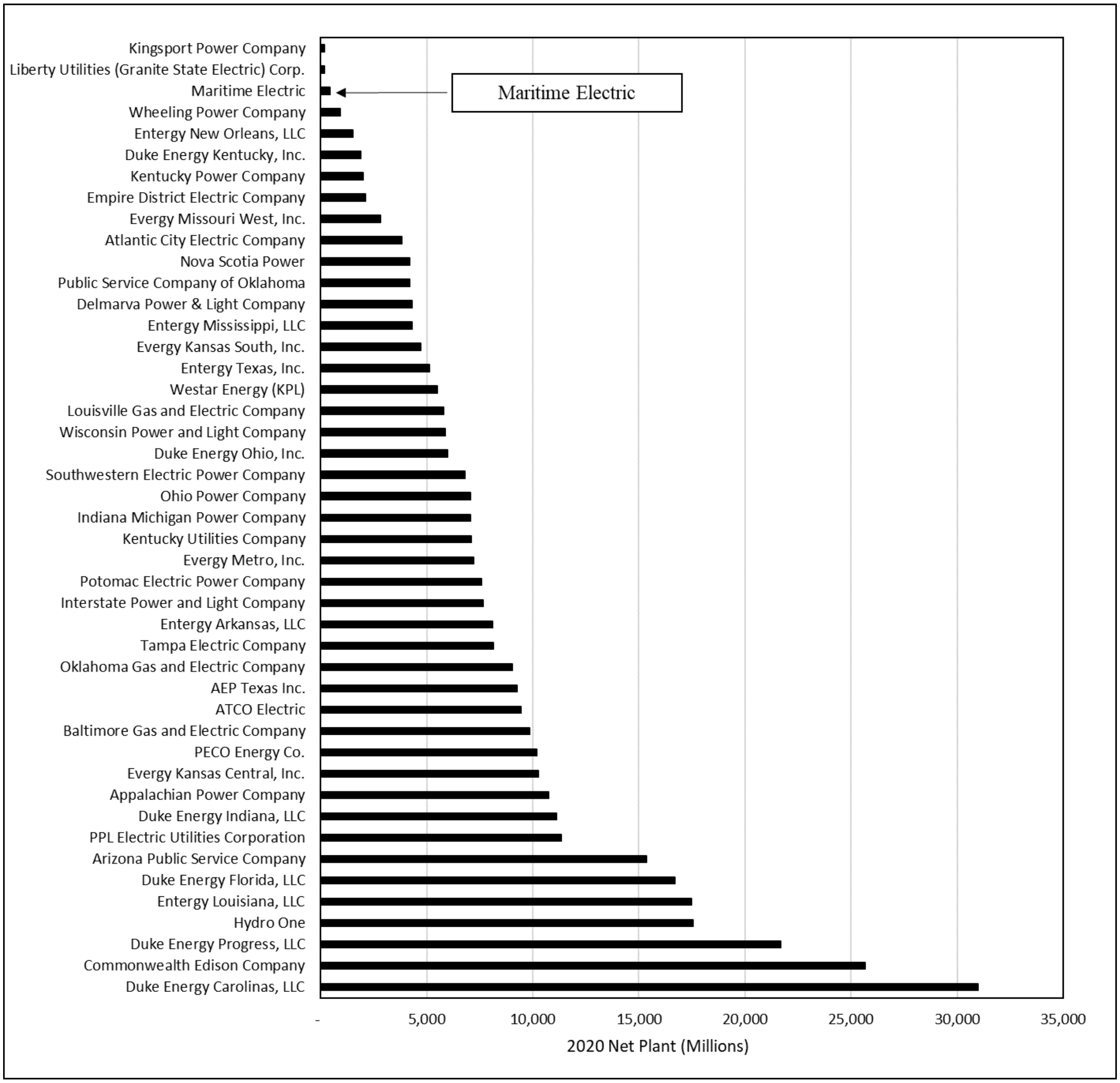
62 Island and Regulatory Appeals Commission, Docket UE 20934, Order UE06-03, at paragraph [28].

Figure 34: Small Size of Maritime Electric
2020 Retail Electric Customers[63]



63 Source: SNL Financial. Data taken from EIA Form 861, released October 2020.

Figure 35: Small Size of Maritime Electric
2020 Net Property, Plant and Equipment



Due to its small size, Maritime Electric has greater risk associated with adverse economic conditions, as well as greater risk that customer demand could decrease significantly due to a major employer or industry experiencing a downturn or deciding to relocate. A small utility cannot diversify its risks to the same extent as larger utilities whose assets, geography and economic bases are less concentrated. Negative events are likely to have greater impact on the earnings and cash flows of a smaller utility. Credit rating agencies consider small size as a risk factor for regulated utilities. For example, in its May 2021 credit report for Maritime Electric, S&P comments on how this affects the Company:

> MECL lacks geographic and regulatory diversity. Compared with its utility peers, the company has a small customer base and lacks geographic and regulatory diversity. Therefore, we consider MECL's business risk to be in the lower half of our excellent range relative to those of its utility peers and we ascribe a negative comparable rating analysis modifier to reflect this.[64]

The risk associated with Maritime Electric's small size has been recognized by the Commission and credit rating agencies and causes investors to require a higher cost of equity to compensate for that risk.

2. Macroeconomic and Demographic Trends

Maritime Electric's service territory is largely rural; Charlottetown is the only major population center. The economy on Prince Edward Island ("PEI") is concentrated in agriculture, fishing, tourism, aerospace, and government. According to the Conference Board of Canada's long-term economic outlook for the province, PEI is projected to have the highest population growth rate in the Atlantic Canada region because it is a top destination for international immigrants. Despite the increase in residents, however, the population will still become "greyer" over the next two decades, limiting additional growth. Among the highlights for PEI, the Conference Board of Canada notes:

- GDP growth should average an annual rate of 1.6 percent over 2023 to 2040, in line with the national profile.
- Record immigration targets from the federal government will lead to a surge in entries over the next few years, which is expected to continue over the forecast period.
- Following a rapid pace of 2.0 percent average annual growth from 2016 to 2020, the average population growth in PEI is projected to settle at 1.3 percent through 2030. The growth will decelerate further to 0.9 percent annually during the last decade of the forecast period.

64 Standard and Poor's Global Ratings, Maritime Electric Company Ltd., May 11, 2021, at 2.

- The labour force participation rate is forecast to fall from 66.5 percent in 2019 to 61.6 percent in 2040. Labour force growth is expected to slow from an average annual pace of 1.7 percent between 2016 and 2021 to 0.9 percent from now to 2040.
- Growth in potential output will average 1.2 percent over the forecast period, which is significantly higher than the other Atlantic provinces.
- The Province hopes to improve energy efficiency and reduce its carbon footprint over the next decade, which will lift non-residential and government investment in clean technologies, such as wind farms and solar energy.
- The pandemic saw a brief decline in housing starts, but we expect a pickup over the medium term. Starts will begin to decelerate starting in 2024.
- Although PEI was certainly the least impacted by the pandemic of all provinces, it still pushed the province into its largest deficit on record in 2020-21.
- PEI exports have been strong in recent years, and this trend is expected to continue over the long-term, with exports growing at a solid 2.5 percent average annual clip over the forecast period.
- PEI's tourism sector will continue to be a key component of growth over the long term. The industry is expected to expand at a healthy 2.8 percent average annual rate over the long term.[65]

Figure 36 compares the projected macroeconomic conditions on PEI to Canada as a whole from 2020-2040. Over the long-term, GDP growth, household disposable income, and housing starts are projected to be weaker than Canada overall, while growth in the labor force is projected to be stronger than Canada overall and population growth and retail sales are expected to trend near the nationwide average.

[65] The Conference Board of Canada, Migration is Key to Island's Future, Prince Edward Island's 20-Year Outlook, August 24, 2021.

Figure 36: Key Economic Indicators[66]

Economic Indicator	PEI 2020-2040	Canada 2020-2040
GDP Growth	1.6%	2.0%
Labor Force	0.8%	0.4%
Population (Labor Force Age)	1.0%	1.0%
Employment	0.9%	1.2%
Household Disposable Income	1.9%	2.9%
Retail Sales	3.0%	3.1%
Housing Starts	(2.2%)	(1.4%)

3. Supply and Operating Risks

Figure 37 presents the sources of the Company's electricity supply in 2021.

Figure 37: Maritime Electric Electricity Supply in 2021[67]

	MWh	%
On-Island oil-fired generation	1,445	0.10%
On-island wind generation (contracted)	280,591	19.40%
Point Lepreau participation (nuclear)	197,670	13.67%
System purchases from NB Power	966,490	66.83%

Due to its island location, Maritime Electric is exposed to relatively high supply and operating risks. In 2021, Maritime Electric depended on New Brunswick Power for approximately 80.5 percent of its energy requirements. The off-island energy supply is delivered from the mainland grid via four provincially-owned submarine cables, two of which were activated in August 2017. Based on conversations with the Company, our understanding is that Maritime Electric acted as Construction Agent to install the two new 180 MW submarine cables between New Brunswick

66 The Conference Board of Canada, Key Economic Indicators for each province, September 2021.
67 Provided by Maritime Electric in response to data request. Source: December 2021 Management Report for energy supply as of December 31, 2021.

and PEI and is responsible for operating and maintaining these cables after they were placed into service. These new submarine cables were intended to enhance the reliability of electricity supply on PEI and to contribute to ongoing efforts to reduce the use of fossil fuels; however, this does not resolve the transmission constraints associated with off-island generation in New Brunswick.

Maritime Electric's dependence on mainland power supplies means that, for reliability purposes, the Company owns on-island generation capacity (90 MW) to serve as back-up in case of supply interruption. While this generation capacity is not intended to be operated on a regular basis, as it is relatively high cost compared to off-island production, Maritime Electric has an obligation to ensure that back-up capability is maintained and available. Rather than refurbishing the existing CTGS units, Maritime Electric determined that it would be more cost effective to design and construct a new combustion turbine. The Company plans to retire and decommission the existing CTGS units in 2023-24. Maritime Electric has been approved to engage an independent consultant to complete an on-Island generation capacity study in 2022, which seeks to determine the optimal location for and type of additional generation capacity on PEI. The study will address whether additional on-Island generation is needed in the form of a new combustion turbine. The Company does not have enough generation if its electricity supply is cut off from New Brunswick. This risk materialized in November 2018, when an ice storm cut off power to PEI for 24 hours.

Weather-related service disruptions represent another important operating risk for Maritime Electric. The Company's service territory is subject to severe ice and wind storms. The need to address supply disruptions caused by severe weather conditions involves unpredictable and potentially volatile capital and operating costs. Maritime Electric's capital structure and allowed ROE must provide the Company with the financial flexibility necessary to respond to unforeseen capital and operating costs in order to restore electric distribution service promptly to customers. Unlike many electric utilities in Canada and the U.S., Maritime Electric does not have a cost recovery mechanism or deferral account for storm-related costs to mitigate this risk, although it was allowed to defer the costs associated with Hurricane Dorian for future recovery in rates.

Lastly, our understanding is that the vast majority of Maritime Electric's renewable energy supply is generated by on-island wind generation facilities. Future renewable energy supply sources are also expected to be largely from wind generation facilities. Given the intermittent nature of wind and solar as sources of generation, there are additional operational and contractual complexities for Maritime Electric which distribution utilities in other provinces do not face to the same degree. In addition, the wind generation facilities are owned by the Province, and Maritime Electric purchases supply through a Power Purchase Agreement. As a result, Maritime Electric has no control over the reliability of the wind facilities, which could be an additional risk associated with renewable energy.

4. Deferral and Variance Accounts

Maritime Electric has very limited protection against costs that tend to fluctuate significantly from year to year, are material in nature, and over which utility management has no control. While several utilities in Canada have deferral and variance accounts to mitigate the risk associated with operating and capital costs, Maritime Electric has relatively few. The only accounts that Maritime Electric has implemented are: 1) the Energy Cost Adjustment Mechanism ("ECAM"), which allows the Company to recover the actual cost of fuel and purchased power compared to the forecasted amount, 2) a weather normalization reserve account that represents the cumulative change in the contribution margin (average selling price less average cost of energy purchased) resulting from variations in heating degree days from normal; and 3) a variance account for OPEB costs.

The most important variance account for Maritime Electric is the ECAM, which has two fundamental purposes: 1) to provide a mechanism that ensures the timely collection or rebate of prudently incurred energy-related costs from customers; and 2) to provide customers a measure of rate predictability by deferring unplanned fluctuations in energy supply costs during a particular rate setting period. When it was originally approved in the 1970s, the ECAM was a fuel adjustment mechanism that automatically adjusted rates on a timely basis to reflect changes in the cost of purchasing and producing electricity. In more recent years, the ECAM has served as a rate smoothing mechanism by accumulating the variance in electricity supply costs from forecast and recovering/repaying that balance over a future period. In the most recent rate filings and during the PEI Energy Accord, the ECAM has been effectively used to provide customer rate predictability over the rate setting period by providing stable basic rates.

The IRAC recently reviewed the ECAM and in July 2021 issued an Order accepting the Company's proposal to remove certain accounts from the mechanism that have little variability or are within the control of Maritime Electric. Adjustment clauses for fuel and purchased power costs have been common for regulated utilities since the 1970s, and are an important risk mitigating measure in terms of providing customers with more stable and predictable rates and allowing the utility to recover variations in fuel and purchased power costs in a timely manner. Because these types of deferral and variance accounts are almost universal, the market data used to estimate the cost of equity reflects investors' expectation that all utility companies have a variance account for fuel and purchased power costs.

In order to mitigate volume/demand risk, the Commission approved Maritime Electric's weather normalization reserve account in 2016. The account normalizes sales based on fluctuations in heating degree days as compared to the rolling ten-year average for the most recent ten years. Among Canadian investor-owned electric utilities, Newfoundland Power has a weather-related variance account that allows it to recover in a future period the difference between projected and actual revenues due to abnormal weather conditions in the test year. FortisBC Electric operates under a revenue stabilization plan that includes full protection against volumetric risk. Nova Scotia Power does not have regulatory protection against volumetric risk. ATCO Electric Distribution and FortisAlberta both operate under a PBR plan that adjusts revenues annually based on inflation less a productivity factor. These plans allow for an annual adjustment for changes in billing determinants through a "Q value." The Q value represents the percentage change in billing determinants, and for electric distribution utilities under the price cap mechanism, this percentage change is calculated across all billing determinants, including energy, demand, and the number of customers.[68] In summary, Maritime Electric has greater volumetric risk than FortisBC Electric and the Alberta electric utilities, comparable volume/demand risk as Newfoundland Power, and lower volume/demand risk than Nova Scotia Power.

5. Alternative Fuel Risk

Maritime Electric no longer faces competition from alternative fuel sources such as fuel oil for space heating needs. The Company has experienced higher than normal sales growth in recent years due to an increase in the use of electric-based space heating (primarily heat pumps), as customers are switching from oil-based heating. Maritime Electric estimates that approximately

[68] Decision 25864-D01-2020, ATCO Electric 2021 Annual Performance-Based Regulation Adjustment (December 18, 2020), pp. 5-6.

40 percent of its customers are currently using electricity for space heating. The electric heat penetration level has increased from 30 percent in 2018 due in large part to incentives from the Government (efficiencyPEI) for energy efficient equipment for heating/cooling and the 10 percent rebate applied on the first block (2000 kwh) for residential customers. In addition, additional demand for electricity is being driven by funding and incentives for electric vehicles and school buses on PEI.

6. Political and Regulatory Uncertainty

With respect to the political environment and regulatory framework, a change in provincial legislation in the mid-1990s greatly altered the regulatory model for Maritime Electric. The legislation replaced rate of return/rate base regulation with price cap regulation that limited the Company's regulated prices to those of NB Power plus 10 percent, thereby exposing Maritime Electric to significant financial pressures. Pursuant to the 2004 Electric Power Act, Maritime Electric was returned to rate of return/rate base regulation and allowed to recover approximately $21 million of costs that had been incurred and deferred pursuant to the prior regulatory framework.

Maritime Electric and the Provincial Government entered into a five-year PEI Energy Accord Agreement for the March 1, 2011 to February 29, 2016 period which, among other things, fixed customer rates and the Company's ROE during this period. As part of the Energy Accord, the government appointed the PEI Energy Commission to undertake a review of PEI's electricity sector. The PEI Energy Commission made several recommendations, including: 1) government ownership of Maritime Electric's existing and future generation assets; 2) a legislatively set reduction in the Company's allowed equity ratio; and 3) government responsibility for demand side management and energy efficiency programs. These recommendations introduced material political risk to the Company. The government acted on the recommendation regarding ownership of Maritime Electric's future generation assets by announcing a policy which provides the government the option to own and finance future generation on PEI. The government also established a target range for Maritime Electric's common equity ratio of at least 35.0 percent but not to exceed 40.0 percent. The active role of government, as demonstrated by past changes in legislation as well as by the broad mandate of the PEI Energy Commission, contributes to a higher degree of political/regulatory risk for the Company and its investors.

7. Summary

Our assessment is that Maritime Electric continues to have many of the same business and operating risks as in prior GRA filings. For example, the Company continues to be very small compared to other investor-owned electric utilities in Canada and the U.S. and serves a limited geographic territory. Furthermore, economic growth on PEI is projected to be slightly weaker than Canada over the long-term, and growth in the Provincial economy is expected to be constrained over the next 20 years due to an aging population. Although the Company has deferral and variance accounts for fuel and purchased power costs and to account for fluctuations in sales due to weather, Maritime Electric does not have some variance and deferral accounts that are common among other regulated electric utilities across Canada. In particular, Maritime Electric does not have a cost recovery mechanism or deferral account for storm-related costs that might be incurred as the result of severe wind and ice storms. Moreover, the level of government involvement and political uncertainty with regard to ownership of generation assets result in increased business and regulatory risk for Maritime Electric. For all of these reasons, our view is that the business risk of Maritime Electric remains above average.

B. Comparison to other Investor-Owned Canadian Electric Utilities

Maritime Electric derives 100 percent of its operating income and revenues from electric utility service. By contrast, the companies in the Canadian proxy group are engaged in diverse businesses, including natural gas distribution, oil and natural gas transmission, merchant generation, development of renewable assets, commodity marketing, and various other unregulated activities. The following is a brief summary of each Canadian proxy group company that is primarily engaged in electric utility service.

Emera, Inc. (the parent of Nova Scotia Power) owns regulated natural gas distribution utilities in Florida and New Mexico, as well as regulated electric utilities in Nova Scotia, Florida, and the Caribbean. Emera also owns a portfolio of competitive electric generating facilities and engages in a physical energy marketing and trading business through its subsidiary, Emera Energy. Emera also owns an equity interest in electricity transmission assets such as Maritime Link and Labrador Link, and owns the Brunswick Pipeline, which transports natural gas from Saint John, New Brunswick to markets in the northeastern U.S. From 2018-2020, Emera derived approximately 92 percent of its operating income from regulated operations.

Canadian Utilities Ltd. ("CU Ltd.") provides gas distribution service, electric distribution and transmission service, and gas transmission service in Alberta through its ATCO Gas, ATCO Electric, and ATCO Pipeline subsidiaries. CU Ltd. Derived approximately 64 percent of its operating income from 2018-2020 from regulated services, with slightly more than half of that regulated operating income from electric utility service. CU Ltd. Also owns unregulated electric generation plants in western Canada and Ontario, operates unregulated natural gas gathering, processing, storage, and transmission businesses, and has regulated and unregulated operations in Australia and Mexico.

Algonquin Power and Utilities Corp. ("APUC") is a diversified mostly energy company with operations across the U.S., Canada, and more recently in Chile and Bermuda. Through Liberty Utilities, APUC owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems. APUC also generates and sells electricity through a portfolio of nonregulated renewable and clear-energy power generation facilities at Liberty Power. APUC also owns a 44.2 percent equity investment in Atlantic Yield PLC.[69] Regulated assets account for approximately 65 to 70 percent of APUC's 2019 cash flow, while the remaining cash flow is from nonregulated generation assets with an average remaining contract life of 14 years.[70] APUC's largest regulated utility is Empire District Electric Company, which provides electric generation, transmission and distribution service in Missouri and Arkansas. APUC derived approximately 86 percent of its operating income from regulated service from 2018-2020.

Hydro One, Ltd. Through its subsidiary, Hydro One Inc., Hydro One Ltd. Operates as an electric transmission and distribution company in Ontario that serves approximately 1.4 million residential and business customers across the province of Ontario, as well as large industrial customers and local distribution companies. It owns 98 percent of the province's transmission capacity and covers approximately 75 percent of the region. Hydro One Ltd. Has a hybrid ownership structure, with the government holding an ownership interest of approximately 47.3 percent, and shareholders controlling the remaining 52.7 percent of outstanding shares. It derived 100 percent of its operating income from regulated electric utility service from 2018-2020.

69 Standard and Poor's Global Ratings, Algonquin Power & Utilities Corp, December 10, 2020, at 4.
70 Morningstar/DBRS, Rating Report Algonquin Power & Utilities Corp., February 10, 2020, at 1.

1. Macro-economic Conditions

Macro-economic conditions on PEI are projected by the Conference Board of Canada to be mixed compared to other Canadian provinces over the long term from 2020-2040. Figure 38 compares the key economic indicators for PEI to those in the provinces where the other five investor-owned electric utilities are located, as well as Quebec. As shown in Figure 38, PEI's key economic indicators over this period are generally stronger than Newfoundland and Labrador and Nova Scotia, but slightly weaker than other Canadian provinces.

Figure 38: Key Economic Indicators – 2020-2040[71]

	PEI	NL	NS	BC	ALB	ONT	QC
GDP Growth	1.6%	0.4%	1.2%	1.8%	2.4%	2.0%	1.7%
Labor Force	0.8%	(0.8%)	0.2%	0.9%	1.4%	1.0%	0.6%
Population	1.0%	(0.7%)	0.2%	0.9%	1.4%	1.1%	0.5%
Employment	0.9%	(0.4%)	0.4%	1.2%	1.7%	1.2%	0.8%
Disposable Inc.	1.9%	1.1%	2.0%	3.4%	3.8%	3.1%	2.5%
Retail Sales	3.0%	1.8%	2.7%	3.3%	4.1%	3.3%	3.2%
Housing Starts	(2.2%)	(7.2%)	(10.5%)	(3.7%)	0.8%	(1.2%)	(7.1%)

2. Capital Cost Recovery

Maritime Electric files a capital budget with the Commission on an annual basis, which includes the Company's capital budget for the upcoming year, as well as a ten-year comparative history. The IRAC reviews Maritime Electric's capital plan and either provides an Order approving the capital budget or modifying it. Similarly, Nova Scotia Power, Newfoundland Power and FortisBC Electric also file for pre-approval of capital expenditures. In Alberta, the Alberta Utilities Commission ("AUC") approved a new PBR plan for distribution utilities for the period 2018-2022.[72] The new PBR plan incorporates significant changes related to the recovery of capital-related costs. The AUC has established two types of capital. Costs associated with Type 1 capital are subject to a true up, but the Type 1 capital criteria are restrictive (*i.e.*, must be extraordinary, not previously in rate base, and required by a third-party, *e.g.*, regulatory or legislative authority).[73]

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71 The Conference Board of Canada, Key Economic Indicators for each province, September 2021.
72 AUC Decision 20414-D01-2016 (December 16, 2016).
73 AUC Decision 20414-D01-2016 (Errata) (February 6, 2017) at para 198.

Electric utilities in Canada are not allowed to earn a cash return on Construction Work in Progress ("CWIP"), but all utilities are permitted Allowance for Funds Used During Construction ("AFUDC"). In summary, Maritime Electric has similar capital cost recovery risk as other investor-owned electric utilities in Canada except for those in Alberta, which have higher risk on certain capital costs.

3. Operating Cost Recovery

Concentric has evaluated Maritime Electric's ability to recover operating costs that (1) tend to fluctuate substantially from year to year, (2) are significant in magnitude, and (3) are generally beyond the control of utility management. Regulators in Canada often use variance and deferral accounts to mitigate the risks associated with these types of costs. As shown in Figure 39, Maritime Electric has a deferral/variance account for pension/OPEB expenses, while other Canadian investor-owned electric utilities have varying levels of protection against these operating costs, with the exception of FortisAlberta, which does not have deferral/variance accounts related to these costs.

Figure 39: Operating Cost Recovery Mechanisms

Utility	Pension/OPEB Expense	Bad Debt Expense	Change in Interest Rates	Energy Efficiency and DSM
Maritime Electric	Yes	No	No	No
ATCO Electric	Yes	No	Yes	No
FortisBC Electric	Yes	No	Yes	Yes
FortisAlberta	No	No	No	No
Newfoundland Power	Yes	No	No	Yes
Nova Scotia Power	No	No	No	No

Importantly, while Maritime Electric has protection against pension and OPEB expenses, the Company does not have the ability to recover extraordinary storm costs despite operating in a service territory characterized by severe ice and wind storms. By comparison, both ATCO Electric and FortisBC Electric have the ability to file an application to recover extraordinary storm costs under the Z factor in their performance based regulation plans.

4. Conclusions on Business Risk Relative to Other Canadian Electric IOUs

While the regulatory framework on PEI is generally supportive of maintaining credit quality, there are certain aspects of the economic and operating environment where Maritime Electric has higher business risk than other Canadian investor-owned electric utilities. Based on the information in this section, we conclude that Maritime Electric generally has greater business risk than other Canadian investor-owned electric utilities. Factors contributing to this higher risk profile include Maritime Electric's small size, lack of economic and geographic diversity, weaker than average GDP growth over the long-term, dependence on one supplier, and weather and storm related risk.

C. Comparison to U.S. Electric Proxy Group

In this section, we compare Maritime Electric to the companies in the U.S. Electric proxy group on the following factors: (1) percentage of regulated electric utility operations; (2) credit rating agency and equity analysts' perspectives on the supportiveness of the U.S. regulatory environment for regulated utilities; (3) assessment of regulatory mechanisms used to mitigate cost recovery risk; and (4) investment risk as measured by the business and financial risk rankings from S&P.

1. Comparison of Regulated Electric Utility Operations

Maritime Electric derives 100 percent of its operating income and revenues from regulated electric utility service. As shown in Exhibit JMC-10, the U.S. Electric proxy group companies derive approximately 98 percent of regulated income and 97 percent of regulated revenues from electric utility service, and approximately 97 percent of regulated assets are dedicated to electric utility operations. For this reason, we conclude that the U.S. Electric proxy group is more representative of Maritime Electric than the Canadian proxy group, which as noted previously is engaged in other regulated utility businesses (such as natural gas distribution), as well as non-regulated activities.

2. Investor Comments on U.S. Regulatory Environment

In September 2013, Moody's issued a report discussing its evolving view of U.S. utility regulation. In that report, Moody's stated:

> Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the U.S.

> utility regulatory environment. Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators.
>
> ***
>
> Our revised view that the regulatory environment and timely recovery of costs is in most cases more reliable than we previously believed is expected to lead to a one notch upgrade of most regulated utilities in the U.S., with some exceptions. This evolving view is independent of the proposed changes in the methodology that are highlighted in the Summary section that follows, and would have taken place even if the 2009 methodology were to remain in place without modification.[74]

This report by Moody's confirms Concentric's assessment of the comparability of the U.S. and Canadian regulatory environments. Concentric contacted Moody's to check if the agency has updated its 2013 report, and the lead utilities rating analyst indicated that 2013 remained its most recent assessment, although it anticipated publishing an update in mid-2022.

More recently, a March 2019 report by equity analysts at Scotiabank indicated that they view the regulatory environments in Canada and the U.S. as being similar for regulated utilities. In explaining why they expect the valuations of Canadian and U.S. utilities to converge, Scotiabank observed:

> Canadian and U.S. valuations should converge. Historically, the Canadian utilities have traded at a premium to their mid-cap U.S. peers. **We attribute this to the historical view that Canadian regulation was superior to U.S. regulation (we no longer have that view)** as well as to strong earnings growth in part due to M&A. As shown in Exhibit 19, based on forward consensus estimates, the Canadian names now trade at a 3x discount.[75]

Further, UBS, a prominent investment bank, ranks regulatory jurisdictions in the U.S. and Canada for purposes of determining whether to apply valuation discounts or premiums to the utility stocks it covers. Specifically, UBS places regulatory jurisdictions into five tiers based on the

[74] Moody's Investors Service, "Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation," September 23, 2013, at 1.

[75] Scotiabank Equity Research Spotlight, Energy Infrastructure, March 18, 2019, at 9. [Emphasis added.]

following equally weighted criteria: (1) whether commissioners are elected or appointed, (2) allowed returns relative to 10-year Treasury notes, (3) mechanisms that reduce regulatory lag, (4) rate and customer bill levels, (5) the tendency to settle or litigate rate cases, and (6) a subjective "investor friendliness" factor.[76] UBS ranked PEI's regulatory environment in Tier 3 out of five in a December 2020 report.[77] UBS also placed Ontario and Newfoundland and Labrador in Tier 3. British Columbia and Nova Scotia were rated more highly by UBS, falling in Tiers 1 and 2, respectively, while Alberta was rated in Tier 4. In the U.S., UBS ranks 18 state jurisdictions in Tier 3, 9 states in Tier 2, and 7 states in Tier 1.

3. Comparison of Business and Regulatory Risk

As discussed below, Maritime Electric generally has comparable business and regulatory risk as the U.S. Electric proxy group. On that basis, we believe it is reasonable and appropriate to consider the DCF and CAPM results for the U.S. proxy group without adjusting those results for differences in regulatory risk between Canada and the U.S.

a) Regulated generation risk: Maritime Electric owns limited regulated generation assets and therefore has lower generation risk than the U.S. Electric proxy group operating companies, the majority of which own regulated generation assets.

b) Fuel and purchased power cost risk: Maritime Electric purchases approximately 78 percent of its power supply from New Brunswick Power; the remaining 22 percent is derived from on-island wind generation. Maritime Electric is allowed to recover variations in energy supply costs through the ECAM. All of the electric utility companies in the U.S. proxy group have adjustment clauses that allow them to pass through fuel and purchased power costs to customers. As such, the U.S. electric utilities are not at risk for differences between the projected and actual cost of fuel and purchased power. In addition, Maritime Electric's predominant reliance on a single source of power (New Brunswick Power Corp.) places it at greater risk of supply disruptions than the electric utilities in the U.S. proxy group.

[76] UBS Global Research, "North America Power & Utilities: Mind the Gap(s): 2021 Utility Outlook," December 14, 2020, at 5.
[77] Ibid., at 6.

c) Regulatory lag: Maritime Electric files rate applications based on a forecasted test year, while 54 percent of operating companies in the U.S. Electric proxy group also use fully or partially forecasted test years. Maritime Electric's revenue requirement is determined based on average regulated equity, while 49 percent of operating companies in the U.S. proxy group use year-end rate base, which provides more timely recovery of capital investments than those with a historic test year, and 51 percent use average rate base.

d) Volume/demand risk: Maritime Electric has a weather normalization adjustment clause that provides regulatory protection against changes in volume/demand caused by abnormal weather conditions. Approximately 8 percent of the operating companies in the U.S. Electric proxy group have full revenue decoupling mechanisms, which provides more protection against volumetric risk than a weather normalization clause, while 46 percent have partial revenue decoupling similar to Maritime Electric.

e) Capital cost recovery risk: Maritime Electric annually files a capital investment plan with the Commission, which approves a specified amount that will be recoverable in future rates. Approximately 79 percent of the operating companies in the U.S. electric utility proxy group either receive pre-approval for capital expenditures and/or are allowed to earn a cash return on CWIP. In addition, approximately 49 percent have one or more cost tracking mechanisms that allow them to recover capital costs between rate cases. Maritime Electric does not have any capital tracking mechanisms and earns AFUDC on capital costs rather than a cash return on CWIP.

f) Operating cost recovery mechanisms: Maritime Electric has been allowed to implement several deferral and variance accounts; likewise, the operating companies in the U.S. Electric proxy group employ similar regulatory protection against specific categories of costs that tend to fluctuate significantly from year to year, are material in nature, and are beyond the control of utility management. A notable exception is that Maritime Electric has no deferral or variance account or other regulatory protection against storm-related costs (both operating and capital costs), which tend to be a significant risk factor in any given year due to climate in the Province. Of the U.S. Electric proxy group companies, 49 percent of the operating companies have a storm-cost recovery account.

In addition to these short-term risks, as discussed previously, Maritime Electric has higher long-term business risk than the U.S. proxy group companies due to the Company's small size in terms of customer base and net utility plant, which heightens the effect of other business risks. In addition, Maritime Electric's service territory is exposed to severe weather conditions, especially wind and ice storms that create significant risk that the Company will incur substantial capital and operating costs to restore service in any given year. Maritime Electric previously had lower business risk than operating companies in the U.S. Electric proxy group as it relates to competition from alternative fuel sources such as natural gas; however, that differential is not as wide as before due to the proliferation of decarbonization policies in certain parts of the U.S. that are impacting the competitiveness of natural gas as an alternative fuel. Maritime Electric is benefiting from the expansion of electric space heating in its service area.

4. Credit Ratings as Measure of Investment Risk

Maritime Electric has a long-term issuer rating of BBB+ from S&P, while the average S&P long-term issuer rating for the U.S. proxy group of electric utility companies is A-/BBB+. Credit ratings are based on both business risk (including an assessment of the regulatory environment in which the utility operates) and financial risk. Companies with similar credit ratings have been determined by the rating agency to have similar levels of business and financial risk. Various regulatory agencies have used credit ratings to assess investment risk. For example, in the U.S., FERC has found that "it is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk."[78] Like FERC, Concentric utilizes credit ratings as one of its screens for proxy companies, but does not see a credit rating as a complete measure of risk for equity investors.

Concentric compared the investment risk of Maritime Electric to that of the U.S. Electric proxy group by analyzing the business and financial risk rankings reported by S&P. As shown in Figure 40, Maritime Electric's Business Risk ranking is "Excellent" and its Financial Risk ranking is "Significant." On that basis, Maritime Electric's Business Risk ranking is comparable to six of the ten companies in the U.S. Electric proxy group, and its Financial Risk ranking is comparable to nine of the ten companies in the U.S. Electric Utility proxy group.

78 *See*, for example, *Potomac-Appalachian Transmission Highline, LLC*, 122 FERC ¶ 61,188 at paragraph 97 (2008).

Figure 40: U.S. Electric Proxy Group – S&P Rankings

Company	S&P Rating	Business Risk	Financial Risk
ALLETE, Inc.	BBB	Strong	Significant
Alliant Energy Corp.	A-	Excellent	Significant
Duke Energy Corporation	BBB+	Excellent	Significant
Edison International	BBB	Strong	Significant
Entergy Corp.	BBB+	Excellent	Significant
Evergy Inc.	A-	Excellent	Significant
IDACORP, Inc.	BBB	Strong	Significant
NextEra Energy, Inc.	A-	Excellent	Intermediate
OGE Energy Corporation	BBB+	Strong	Significant
Portland General Electric Co.	BBB+	Excellent	Significant
Maritime Electric Co. Ltd.	**BBB+**	**Excellent**	**Significant**

D. Financial Risk

Financial risk exists to the extent a company incurs debt obligations in financing its operations. These fixed obligations increase the level of income required to cover interest payments before common stockholders receive any return. Fixed financial obligations also reduce a company's financial flexibility and its ability to respond to adverse economic circumstances and capital market conditions.

The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations and is a function of the percentage of debt (or financial leverage) in the capital structure. As the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress for common equity holders (i.e., financial risk) also increases.[79] Since the capital structure can affect the Company's overall level of risk, it is an important consideration in establishing a fair return.

[79] *See* Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 45-46.

Under the provisions of the revised Electric Power Act, Maritime Electric is required to maintain a minimum of at least 35 percent common equity and not more than 40 percent common equity in its capital structure.

Maritime Electric issues First Mortgage Bonds ("FMB") to finance its rate base investments rather than senior unsecured debt. These FMBs, which are typically in the range of $40 million or less, are sold through private placements with Canadian-based insurance companies rather than in the public debt market. The supply of potential investors is limited for Maritime Electric's debt offerings. For example, when the Company issued debt in 2018, it solicited ten potential investors and three participated in the offering. The Company issued $40 million of FMBs in December 2018 with a 40 year term at a yield of 4.148 percent, which represents a spread of 175 basis points above the Benchmark Bond. Maritime Electric's FMBs are rated "A" by S&P because the funds are secured by the utility assets of the Company. It is generally riskier for companies to issue FMBs than unsecured debt because the utility is agreeing to use its assets as collateral to secure the loan. Maritime Electric, however, has no choice but to issue FMBs due to the small size of the debt offering, which is a function of the small size of the Company itself.

1. Comparison to Other Investor-Owned Electric Utilities

One way to assess the reasonableness of Maritime Electric's proposed equity ratio is by comparison to other investor-owned electric utilities. As shown in Figure 41, Maritime Electric's proposed common equity ratio of 40 percent is consistent with the average common equity ratio of 39.9 percent for the other Canadian investor-owned electric utilities and slightly below the midpoint of the range of equity ratios from 37 percent to 45 percent.

Figure 41: Comparison of Authorized Equity Ratios

Operating Utility	Equity Ratio
Maritime Electric (current)	**40.0%**
Maritime Electric (proposed)	**40.0%**
Alberta Electric Distributors	37.0%
FortisBC Electric	40.0%
Newfoundland Power	45.0%
Ontario Electric Distributors	40.0%
Nova Scotia Power	37.5%
Canadian Average	**39.9%**
U.S. Electric Utilities	**49.3%**

According to Regulatory Research Associates, the average authorized common equity ratio for U.S. electric utilities in 2021 was 49.3 percent, or more than nine percentage points higher than Maritime Electric's proposed common equity ratio of 40.0 percent.

2. Assessment of Credit Metrics

Financial risk is also measured through credit metrics, such as the ratio of Funds From Operations ("FFO") to debt, as well as interest coverage ratios that compare Earnings Before Interest and Taxes ("EBITDA") and FFO to interest payments on long-term debt. As shown in Exhibit JMC-11, the S&P adjusted credit metrics for Maritime Electric in 2020 were generally stronger than the companies in the Canadian proxy group, but weaker than the average for the U.S. Electric proxy group, especially with respect to interest coverage ratios and debt to capital ratios. The 2021 estimated credit metrics for Maritime Electric indicate that FFO ratios were projected to decline compared to 2020. Figure 42 summarizes the key credit metrics for Maritime Electric and the average credit metrics for the companies in the Canadian proxy group and the U.S. Electric proxy group.

Figure 42: 2021 S&P Credit Metrics Comparison

Credit Metric	Maritime Electric 2021 Estimated	Maritime Electric 2020 Actual	Maritime Electric 2017	Canadian	U.S. Electric
Debt to Capital Ratio	64.9%	68.3%	63.0%	55.0%	55.9%
EBITDA to Interest Coverage	4.65	4.02	4.69	4.27	5.25
FFO to Interest Coverage	2.80	3.01	4.93	4.35	5.90
FFO/Debt (%)	14.2%	17.4%	20.6%	12.1%	16.2%
Debt/EBITDA	4.25	4.31	3.65	6.35	5.19

As shown in Figure 42, compared to the Canadian proxy group, Maritime Electric has a higher (i.e., weaker) debt to capital ratio, a stronger EBITDA to interest coverage ratio, a weaker FFO to interest coverage ratio, a stronger FFO/Debt ratio, and a stronger Debt/EBITDA ratio. Compared to the U.S. Electric proxy group, Maritime Electric has a higher (i.e., weaker) debt to capital ratio, a weaker EBIDTA to interest coverage ratio, a much weaker FFO to interest coverage ratio, a weaker FFO/Debt ratio, and a stronger Debt/EBITDA ratio.

Maritime Electric's FFO to Interest Coverage and FFO/Debt metrics have weakened since 2017. Based on a comparison of the equity ratios and the credit metrics of Maritime Electric to the companies in the Canadian and U.S. proxy groups, our conclusion is that the Company has higher financial leverage, and weaker FFO to interest coverage and weaker FFO/Debt ratios than the Canadian and U.S. Electric proxy groups.

3. Credit Rating Agency View

Maritime Electric has consistently maintained a long-term issuer rating from S&P of "BBB+" since January 2004. A May 2021 S&P report reaffirmed the current rating for Maritime Electric, noting the generally supportive regulatory framework and business environment on PEI. However, S&P expressed some degree of caution with respect to the risk of political interference, noting that "the provincial government plays a significant and active role in establishing energy policy and setting rates for the island's customers."[80] Maritime Electric's Business Risk is ranked as

80 Standard and Poor's Global Ratings, Maritime Electric Company Ltd., May 11, 2021, at 2.

"Excellent" by S&P, which is consistent with four of the six companies in the Canadian proxy group. The other two companies (Algonquin Power and AltaGas) have "Strong" Business Risk rankings. In terms of Financial Risk, S&P ranks Maritime Electric as having "Significant" financial risk. As shown in Figure 43, four companies in the Canadian peer group also have "Significant" Financial Risk rankings, while Emera and AltaGas have "Aggressive" Financial Risk rankings.

Figure 43: Canadian Proxy Group – S&P Rankings

Company	S&P Rating	Business Risk	Financial Risk
Algonquin Power and Utilities Corp.	BBB	Strong	Significant
AltaGas Ltd.	BBB-	Strong	Aggressive
Canadian Utilities Ltd.	A-	Excellent	Significant
Emera, Inc.	BBB	Excellent	Aggressive
Enbridge, Inc.	BBB+	Excellent	Significant
Hydro One, Ltd.	A-	Excellent	Significant
Maritime Electric Co. Ltd.	**BBB+**	**Excellent**	**Significant**

4. Conclusions on Proposed Equity Ratio

Maritime Electric is proposing a capital structure consisting of 40 percent average common equity and 60 percent average long-term debt. Maritime Electric's proposed equity ratio is consistent with the average authorized equity ratio for the Canadian proxy group, but substantially lower than the average authorized equity ratio of 49.3 percent for U.S. electric utility companies in 2021. For those reasons, our conclusion is that Maritime Electric's proposed common equity ratio of 40 percent is lower than that justified by its risk profile but consistent with the range established by the Electric Power Act and should be adopted by the Commission.

VII. EARNINGS SHARING MECHANISM

Maritime Electric is not requesting an Earnings Sharing Mechanism ("ESM") in this GRA. However, the Company's hard cap on earnings is more restrictive than many other utilities in Canada or the U.S., most of which are allowed to retain all or a percentage of earnings above the authorized level, as shown previously in Figure 33. Our research indicates that many utilities in Canada and the U.S. operate under an ESM that allows utilities to keep 100 percent of earnings within a specified deadband, typically 50-100 basis points above the authorized ROE, and to share with customers a percentage of earnings in excess of that deadband. As such, Maritime Electric does not have the same financial incentive to improve its operational efficiency and reduce its costs as other utilities that are allowed to retain a portion of these cost savings,. The Company's equity investors are precluded from enjoying the benefits of such a plan. In summary, from a policy perspective, the hard cap on Maritime Electric's earnings restricts the Company's ability to earn above its authorized ROE, unlike many other regulated utilities in Canada and the U.S., and does not provide a financial incentive for Maritime Electric to pursue operating efficiencies and cost savings. Under an ESM, customers also benefit from enhanced efficiency and savings.

Exhibit JMC-12 provides examples of other Canadian and U.S. regulated electric and gas utilities with an ESM.

VIII. OVERALL CONCLUSIONS AND RECOMMENDATIONS

For the reasons discussed throughout this report, it is appropriate to consider the results of the CAPM, DCF and Risk Premium models when establishing the authorized ROE for Maritime Electric. The results of those analyses are summarized in Figure 44.

Figure 44: Summary of Results (Including flotation costs)

	Canadian Regulated Utilities	US Electric	North American Electric	Average
Constant Growth DCF	12.08%	9.77%	10.12%	10.7%
Multi-Stage DCF	10.48%	8.96%	9.21%	9.6%
CAPM	10.35%	10.79%	10.48%	10.5%
Risk Premium		10.01%	10.01%	10.0%
Average	11.0%	10.0%	10.1%	10.4%

The average of all methods for the U.S. Electric proxy group is 10.0 percent, within the range of 8.96 percent to 10.79 percent. From within this range, the Company's proposed ROE of 9.95 percent is reasonable, if not conservative. The average for Canadian regulated utilities, several of which have unregulated business activities and many of which do not own any regulated generation, is 11.0 percent, while the average for the North American Electric proxy group is 10.1 percent.

Concentric's opinion is that the proposed 9.95 percent ROE and 40.0 percent equity ratio taken together are reasonable, and provide the Company with the financial strength required to meet its debt service obligations while providing a fair return to its shareholders.

JAMES M. COYNE

Senior Vice President

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before federal, state and provincial jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University and an M.S. in Resource Economics from the University of New Hampshire.

AREAS OF EXPERTISE

Energy Regulation

- Rate policy
- Cost of capital
- Incentive regulation
- Fuels and power markets

Management and Business Strategy

- Fuels and power market assessments
- Investment feasibility
- Corporate and business unit planning
- Benchmarking and productivity analysis

Financial and Economic Advisory

- Valuation analysis
- Due diligence
- Buy and sell-side advisory

Litigation Support and Expert Testimony

- Rate and regulatory policy
- Fuels and power markets
- Contract litigation
- Valuation and damages

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

University of New Hampshire
M.S., Resource Economics, *with honors*, 1981

Georgetown University
B.S., Business Administration and Economics, *cum laude*, 1975

DESIGNATIONS AND AFFILIATIONS

Community Rowing Inc., Board of Directors, 2015 - 2019

Georgetown University, Alumni Admissions Interviewer, 1988 – current

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001

American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996

National Petroleum Council, Regulatory and Policy Task Forces, 1992

President, International Association for Energy Economics, Dallas Chapter, 1995

Gas Research Institute, Economics Advisory Committee, 1990-1993

NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984

PUBLICATIONS AND RESEARCH

"Advancing FERC's Methodology for Determining Allowed ROEs for Electric Transmission Companies," submitted to FERC on behalf of EEI, James Coyne, Joshua Nowak and Julie Lieberman, May, 2020.

"Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation", James M. Coyne, Robert C. Yardley, Jr. and Jessalyn G. Pryciak, Energy Regulation Quarterly, Volume 6, Issue 3, 2018.

"Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.

"Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007

"Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006

"Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004

"Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003

"The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001

Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992

"Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

"The Market Risk Premium: An In-Depth Review", Society of Utility and Regulatory Financial Analysts 53rd Financial Forum, Richmond, VA, April 28,2022

"Energy Sector in Transition", Ontario Energy Association, Toronto, ON, September 24, 2018.

"Understanding Regulated Utilities in Today's Capital Markets", NARUC Annual Meeting, La Quinta, CA, November 14, 2016.

"Rate of Return: Where the Regulatory Rubber Meets the Road," CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.

"Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015

"M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010

"The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010

"A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008

"Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005

"The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005

"Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005

"The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005

"Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002

"Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001

"Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001

"Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999

"New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999

"Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998

"Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Alberta Beverage Container Management Board				
Alberta Beverage Container Management Board	2016 2019	Expert for the Board	N/A	Return Margin on Bottle Depots
Alberta Utilities Commission				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
Enmax Power Corporation	2017	Enmax	22570	Cost of Common Equity
Enmax Power Corporation	2020	Enmax	24110	2021 Generic Cost of Capital
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	Project 3698852	Cost of Capital (Gas and Electric Distribution)
FortisBC	2022	FortisBC Utilities		Cost of Capital (Gas and Electric Distribution)
California Public Utilities Commission				
San Diego Gas & Electric Company	2019	San Diego Gas & Electric Company	A-19-04-014	Cost of Capital (Gas Distribution)
San Diego Gas & Electric Company	2021	San Diego Gas & Electric Company	A-21-08-014	Cost of Capital (Electric & Gas Distribution)
Canada Energy Regulator				
Enbridge Pipelines Inc.	2021	Enbridge Pipelines Inc.	RH-001-2020	Cost of Capital (Oil Pipeline)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	Docket Nos. ER11-2909 and EL11-29	Rate of Return (Electric Transmission)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startran IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Northern States Power Company	2019	Northern States Power Company	ER20-26-000	Cost of Capital (Electric Transmission)
PPL Electric Utilities Corp.	2020	PP&l Industrial Customer Alliance v. PPL Electric	EL20-48-000	Answering Testimony in Response to a Section 206 ROE Complaint
South First Energy Operating Companies	2020	South First Energy Operating Companies	ER21-253-000	Cost of Capital (Electric Transmission)
Florida Public Service Commission				
Florida Power & Light Company	2021	Florida Power & Light Company	Docket No. 20210015-EI	Cost of Capital (Electric)
Hawaii Public Utility Commission				
The Gas Company	2017	The Gas Company	Docket No. 2017-0105	Cost of Capital (Gas Distribution)
Maine Public Utilities Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Enmax Corporation	2019	Enmax Corporation	2019-00097	Regulatory Approval of Emera Maine Acquisition
Versant Power	2021	Versant Power	MPUC Docket No. 2020-00316	Cost of Capital (Electric)
Maryland State Board of Contract Appeals				
Green Planet Power Solutions	2018	Green Planet Power Solutions and Maryland Bio Eneregy LLC v. Maryland Department of General Services	MSBCA 3061	Contract Litigation, Power Purchase Agreement, Damages Analysis
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Minnesota Public Utilities Commission				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Northern States Power Company	2017	Northern States Power Company	E002/M-17-797 G002/M-17-787 E002/M-17-818	Cost of Capital (Electric and Gas Rate Riders for Transmission, Renewable Generation and Gas Distribution)
New Brunswick Energy and Utilities Board				
Liberty Utilities (Gas New Brunswick) LP	2021	Liberty Utilities (Gas New Brunswick) LP	491	Cost of Capital (Gas)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2016	Newfoundland Power	2016 GRA	Cost of Capital (Electric)
Newfoundland Power	2018	Newfoundland Power	2018 GRA	Cost of Capital (Electric)
Newfoundland Power	2021	Newfoundland Power	2021 GRA	Cost of Capital (Electric)
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Nova Scotia Power Inc.	2022	Nova Scotia Power Inc.	2022 GRA	Return on Equity/Business Risk (Electric)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
Ontario Power Generation	2020	Ontario Power Generation	EB-2020-0290	Capital Structure (Electric Generation)
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015-2017	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
U.S. Department of Commerce				
Government of Québec	2017	Duty Investigation of Uncoated Groundwood Paper from Canada	PUC Docket No. 29206	Contracting for Renewable Resources, Market Analysis, Damages Analysis
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)
Green Mountain Power Corporation	2018	Green Mountain Power Corporation	18-0974	Return on Equity (Electric)
State Corporation of Virginia				
Dominion Energy Virginia	2021	Virginia Electric and Power Company	PUR-2021-00058	Cost of Capital (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)
Northern States Power Company	2017 2019	Northern States Power Company	PSCW Docket No. 4220-UR-123, 4220-UR-124	Return on Equity (Gas & Electric)
Northern States Power Company	2021	Northern States Power Company	4220-UR-125	Cost of Capital (Electric, Affidavit)
Yukon Utilities Board				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)

JOHN P. TROGONOSKI

Assistant Vice President

Mr. Trogonoski has nearly 30 years of experience in financial and economic analysis, utility regulation, due diligence, business valuation, property taxation, and program administration. Mr. Trogonoski has assisted clients with a variety of regulatory matters, including providing expert testimony and reports on cost of capital, merger approval, and business and financial risk analysis in both the U.S. and Canada. Prior to joining Concentric, Mr. Trogonoski was a member of the Staff of the Colorado Public Utilities Commission where he supervised the financial analysts in the energy and telecommunications sections and filed expert testimony on matters such as rate of return, cost allocation, rate design, incentive regulation, and public policy. He has an M.S. in Business Administration and a B.S. in Marketing from the University of Colorado at Denver.

REPRESENTATIVE PROJECT EXPERIENCE

Utility Consulting

- Filed expert testimony on behalf of ABACO Energy Services, LLC before the Montana Public Service Commission in July 2020. Testimony included recommendations on revenue requirement, rate base, O&M expenses, cost of capital, income taxes and rate design issues. This was ABACO's first ever rate case filing after the small propane company came under the Commission's jurisdiction.
- Testified on behalf of Maritime Electric Company Ltd. on cost of capital and a proposed earnings sharing mechanism before the Island Regulatory and Appeals Commission in Prince Edward Island in August 2019.
- Testified on behalf of Vermont Gas Systems, Inc. on cost of capital before the Vermont Public Utility Commission in September 2019.
- Filed expert testimony on behalf of Community Utilities of Pennsylvania Inc. on cost of capital before the Pennsylvania Public Utility Commission in March 2019.
- Drafted an expert report on the appropriate return margin for the Alberta bottle depots on behalf of the Beverage Container Management Board in June 2019.
- Filed expert testimony on behalf of Hydro-Quebec Distribution and Transmission in support of the Company's request to the Régie de l'energie to modify its allowed return on equity. Performed risk analysis to determine whether it was appropriate to consider a U.S. peer group of regulated electric utilities as an appropriate proxy group for purposes of establishing the allowed ROE for Hydro-Quebec. This analysis included review of the business and financial risks of Canadian and U.S. peer groups on factors that are important to investors in assessing the relative risks of these companies and the regulatory protections that help to mitigate those risks.
- Prepared expert testimony and exhibits for return on equity analysis for numerous North American gas and electric utility clients. This included preparing direct testimony, responding

to data requests, drafting rebuttal testimony in response to intervening witnesses, assisting with hearing preparation, and drafting post-hearing statements of position.

- Prepared expert testimony and exhibits for multiple clients seeking regulatory approval of mergers and acquisitions. This included summarizing credit rating agency reactions to the proposed mergers, researching merger approval standards, analyzing the benefits of increased financial scale in the utility industry, and developing financial and ring-fencing commitments in order to mitigate any risk that might result from the merger.
- Performed regulatory due diligence for clients considering the potential acquisition of a natural gas distribution company and an electric transmission company. Due diligence included a review of the regulatory framework in the jurisdiction of the target company, potential cost disallowances, an assessment of the projected ROE and capital structure, an evaluation of the reasonableness of projected capital spending based on forecasted economic growth in the service territory, and the implications of these factors on the value of the target company.
- Assisted in the development of a conservation program for New Jersey American Water, which was filed with the Board of Public Utilities in conjunction with the company's rate case. The program included rebates for various indoor and outdoor plumbing fixtures, as well as estimated penetration of the proposed rebate programs, and a cost/benefit analysis in support of the various rebates.
- Reviewed de-list bids filed with the ISO New England by a merchant generation company that wished to withdraw from the Forward Capacity Market. Also prepared user manuals for ISO New England to assist project sponsors in completing a request to provide new supply generation in the Forward Capacity Market, and to assist market participants in completing a request to de-list existing capacity.
- Analyzed the internal policies and tariff of New Mexico Gas in response to service outages and determined if the time to restore service to customers was consistent with other major gas distribution outages that have occurred across the United States. Offered recommendations to improve the Company's communication with regulators and customers.
- Assisted in the development of a business valuation for Poseidon Water, LLC by reviewing and validating cost assumptions for construction costs, water rates, and electricity prices. Also developed cost of capital studies for proxy groups of regulated water utilities and wholesale power generators for use in this valuation.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2008 – Present)
Assistant Vice President (2020)
Senior Project Manager (2013)
Project Manager (2010)
Senior Consultant

Colorado Public Utilities Commission (1999 – 2008)
Supervisory Financial Analyst, Telecommunications and Energy (2004)
Financial Analyst, Telecommunications, Energy and Water

State of Colorado, Division of Property Taxation (1994 – 1999)
Property Tax Specialist

Nobel Sysco, Inc. (1992 – 1994)
Marketing Associate

State of Colorado, Division of Property Taxation (1989 – 1991)
Tax Appraiser Consultant

EDUCATION

University of Colorado at Denver
M.S. in Business Administration, 1987
B.S. in Marketing (cum laude), 1986

EXPERT REPORTS

- Drafted a report for the Ontario Energy Board that reviewed low-income energy assistance programs that have been implemented in other jurisdictions, including Canada, the United States, the United Kingdom, the European Union countries, Australia, and New Zealand. Attended hearing and responded to questions related to research report on behalf of OEB staff.
- Drafted a report for the Ontario Energy Board that proposed revisions to the Board's existing rules for Demand Side Management for gas distribution companies in Ontario. Participated in workshop and responded to questions from stakeholders regarding the proposed changes to the Board's rules.

REGULATORY COMMISSION EXPERIENCE

- Supervised financial analysts and accountants in the energy and telecommunications units of the Colorado Public Utilities Commission from 2004 to 2008. In this capacity, he was responsible for the financial analysis, accounting, and auditing work of between five and nine financial analysts. This included preparation of expert testimony and recommendations concerning rate cases, applications for alternative forms of regulatory treatment, performance of managerial and financial audits, compliance with relevant statutes and Commission rules, and review of applications for certificates of public convenience and necessity, transfers of authority, franchise agreements, and discontinuance of service.
- Provided expert testimony on rate of return issues, capital structure, cost of debt, financial integrity, and credit quality in numerous rate case proceedings involving energy, telecommunications and water companies including Xcel Energy, Qwest Corporation, and Atmos Energy.

- Performed managerial and financial audits of regulated energy and telecommunications companies using the regulatory and accounting guidelines in the Uniform System of Accounts relied upon by the Federal Energy Regulatory Commission, the Federal Communications Commission, the Financial Accounting Standards Board, and the Commission's rules and regulations.
- Led Staff's review of an application for relaxed regulatory treatment by Qwest Corporation. Provided expert testimony regarding Qwest's market share in Colorado relative to cable providers, wireless providers, and Competitive Local Exchange Carriers. Assisted professional market research firm in designing questionnaire to examine customer preferences for purchasing telecommunications services, expectations concerning price and quality of those services, and desire for regulation over those services.
- Led Staff's investigation into a Competitive Local Exchange Carrier who was providing regulated telephone service to over 14,000 customers without the requisite Commission authority and without an effective tariff. This investigation resulted in a Commission order to cease and desist provision of regulated services, an order to transfer customers to an alternative provider, and sanctions against the principals.
- Administered the Colorado High Cost Support Mechanism, which provided universal telecommunications service to customers in rural, high costs areas through an assessment on all Colorado customers. Also, later supervised the position that administered this program.

PUBLICATIONS AND RESEARCH

- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with James Coyne), Public Utilities Fortnightly, May 2010

OTHER ACTIVITIES

- Member of 401(k) investment committee at Concentric Energy Advisors, Inc. since 2011.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Beverage Container Management Board (Alberta)				
Beverage Container Management Board	2019	Beverage Container Management Board	N/A	Return margin for Alberta bottle depots
Colorado Public Utilities Commission				
Colorado PUC Staff	2000	Qwest Corporation	99A-577T	Capital Structure Cost of Capital Cost of Debt Composite Income Tax Rate Interest During Construction factor Ad Valorem Tax factor
Colorado PUC Staff	2001	Peetz Cooperative Telephone	01S-321T	Cost of Capital Revenue Requirement Adjustments to Rate Base Adjustment to Operating Expenses Imputed Capital Structure Capital Credit Rotation
Colorado PUC Staff	2002	Mile High Telecom	02C-082T	Order to show cause Operating without CPCN or tariff Violation of stipulation – alleged fraud
Colorado PUC Staff	2002	Public Service Company of Colorado – Electric/Gas	02S-315EG	Cost of Capital Dissolution of PS Credit Corporation Financial Integrity and credit ratings Impact of NRG on regulated entity Dividend payments and capital spending
Colorado PUC Staff	2003	Aquila Networks, Inc.	02S-594E	Cost of Capital
Colorado PUC Staff	2003	Lake Durango Water Company	03S-052W	Allowable expenses – depreciation and taxes Value of purchased water Operating Ratio method Rate design for retail and bulk customers Customer impact of proposed rates Enhancement of accounting & financial reports
Colorado PUC Staff	2003	Roggen Telephone	03S-246T	Cost of Capital
Colorado PUC Staff	2003	South Park Telephone	03A-277T	Request for HCSM support Adjustments to Rate Base Disallowance of Expenses Depreciation rates and USF impact Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Colorado PUC Staff	2003	Pine Drive Telephone	03S-314T	Cost of Capital
Colorado PUC Staff	2003	Phillips County Telephone	03S-315T	Cost of Capital
Colorado PUC Staff	2004	Aquila Networks, Inc.	04S-035E	Cost of Capital
Colorado PUC Staff	2004	SC TxLink, LLC	04A-508	CPCN for CLEC authority Financial Assurance - bonding
Colorado PUC Staff	2005	Qwest Corporation	04A-411T	History of CLEC competition since 1996 Wireless competition in Colorado Is Wireless substitute for wireline? Financial barriers to entry Introduce customer survey Analyze and interpret survey results Regulation of retail service in 14 states
Colorado PUC Staff	2005	Public Service Company of Colorado – Gas	05S-264G	Cost of Capital – investor owned Rate design issues in Phase 2 – S&F Charge Impact on rate of return – minimum system
Colorado PUC Staff	2005	Public Service Company of Colorado - Steam	05S-369ST	Cost of Capital
Colorado PUC Staff	2006	Public Service Company of Colorado - Electric	06S-234EG	Cost of Capital Credit quality and cash flow Financial integrity and credit ratings Purchased power and imputed debt Performance based regulatory plan
Colorado PUC Staff	2007	Public Service Company of Colorado - Gas	06S-656G	Cost of Capital Financial integrity and credit ratings
Colorado PUC Staff	2007	Nunn Telephone	07A-124T	Overview of HCSM statutes and rules Information required by CRS 40-15-208 Use of separation program – revenue requirement Challenges faced with new petition process
Island Regulatory and Appeals Commission (Prince Edward Island)				
Maritime Electric Company, Ltd.	2018	Maritime Electric Company, Ltd.	UE20944	Cost of Capital
Montana Public Service Commission				
ABACO Energy Services, LLC	2020	ABACO Energy Services, LLC	D2020.07.082	Revenue Requirement, Rate Design, and Cost of Capital.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New Brunswick Energy and Utilities Board				
Liberty Utilities (Gas New Brunswick) LP	2021	Liberty Utilities (Gas New Brunswick) LP	491	Cost of Capital (Rebuttal)
New York Public Service Commission				
New York State Gas and Electric Company and Rochester Gas and Electric	2015	New York State Gas and Electric Company and Rochester Gas and Electric	15G-0284	Cost of Capital (Rebuttal)
Niagara Mohawk Power Corporation d/b/a National Grid	2017	Niagara Mohawk Power Corporation d/b/a National Grid	17-E-0238 17-G-0239	Cost of Capital (Rebuttal)
Pennsylvania Public Utility Commission				
Utilities, Inc.	2019	Community Utilities of Pennsylvania, Inc.	R-2019-3008947	Cost of Capital
Régie de l'Energie du Quebec				
Hydro Quebec Distribution and Hydro Quebec TransÉnergie	2013	Hydro Quebec Distribution and Hydro Quebec TransÉnergie	R-3842-2013	Risk analysis in support of ROE testimony
Vermont Public Utility Commission				
Vermont Gas Systems, Inc.	2019	Vermont Gas Systems	19-0513-TF	Cost of Equity
Subpoenas to Provide Expert Testimony				
U.S. Bankruptcy Court – Denver, CO	2005	ON Systems, Inc.	N/A	Testify in U.S. bankruptcy court - value of CPCN for local exchange telecom service
U.S. District Court, Southern District of Florida	2008	USA vs. Wetherald, et al	06-80199-CR-MARRA	Testify on behalf of U.S. government Wire fraud, mail fraud, money laundering

CANADIAN PROXY GROUP

Company	Ticker	Constant Growth DCF	Multi-Stage DCF	Average CAPM	Risk Premium	Average ROE
Algonquin Power and Utilities	AQN	14.49%	11.13%	10.45%		12.02%
AltaGas Inc.	ALA	12.26%	9.25%	12.27%		11.26%
Canadian Utilities Limited	CU	8.91%	9.25%	9.68%		9.28%
Emera Inc.	EMA	10.65%	9.35%	8.52%		9.50%
Enbridge Inc.	ENB	15.27%	13.27%	10.06%		12.87%
Hydro One, Ltd.	H	7.91%	7.62%	8.12%		7.88%
MEAN		11.58%	9.98%	9.85%		10.47%
Flotation		0.50%	0.50%	0.50%		0.50%
MEAN (including flotation)		12.08%	10.48%	10.35%		10.97%

U.S. ELECTRIC PROXY GROUP

Company	Ticker	Constant Growth DCF	Multi-Stage DCF	Average CAPM	Risk Premium	Average ROE
ALLETE, Inc.	ALE	9.55%	9.09%	10.27%	10.01%	9.73%
Alliant Energy Corporation	LNT	8.96%	7.86%	9.92%	10.01%	9.19%
Duke Energy Corporation	DUK	10.10%	9.04%	9.69%	10.01%	9.71%
Edison International	EIX	8.92%	9.14%	10.56%	10.01%	9.66%
Entergy Corporation	ETR	7.26%	8.20%	10.69%	10.01%	9.04%
Evergy Inc	EVRG	10.12%	8.72%	10.36%	10.01%	9.80%
IDACORP, Inc.	IDA	7.31%	7.37%	9.67%	10.01%	8.59%
NextEra Energy, Inc.	NEE	11.44%	7.34%	10.25%	10.01%	9.76%
OGE Energy Corporation	OGE	8.08%	9.01%	11.38%	10.01%	9.62%
Portland General Electric Company	POR	11.00%	8.81%	10.14%	10.01%	9.99%
MEAN		9.27%	8.46%	10.29%	10.01%	9.51%
Flotation		0.50%	0.50%	0.50%		0.50%
MEAN (including flotation)		9.77%	8.96%	10.79%		10.01%

NORTH AMERICAN ELECTRIC PROXY GROUP

Company	Ticker	Constant Growth DCF	Multi-Stage DCF	Average CAPM	Risk Premium	Average ROE
Algonquin Power and Utilities	AQN	14.49%	11.13%	10.45%		12.02%
Canadian Utilities Limited	CU	8.91%	9.25%	9.68%		9.28%
Emera Inc.	EMA	10.65%	9.35%	8.52%		9.50%
Hydro One, Ltd.	H	7.91%	7.62%	8.12%		7.88%
ALLETE, Inc.	ALE	9.55%	9.09%	10.27%	10.01%	9.73%
Alliant Energy Corporation	LNT	8.96%	7.86%	9.92%	10.01%	9.19%
Duke Energy Corporation	DUK	10.10%	9.04%	9.69%	10.01%	9.71%
Edison International	EIX	8.92%	9.14%	10.56%	10.01%	9.66%
Entergy Corporation	ETR	7.26%	8.20%	10.69%	10.01%	9.04%
Evergy Inc	EVRG	10.12%	8.72%	10.36%	10.01%	9.80%
IDACORP, Inc.	IDA	7.31%	7.37%	9.67%	10.01%	8.59%
NextEra Energy, Inc.	NEE	11.44%	7.34%	10.25%	10.01%	9.76%
OGE Energy Corporation	OGE	8.08%	9.01%	11.38%	10.01%	9.62%
Portland General Electric Company	POR	11.00%	8.81%	10.14%	10.01%	9.99%
MEAN		9.62%	8.71%	9.98%	10.01%	9.56%
Flotation		0.50%	0.50%	0.50%		0.50%
MEAN (including flotation		10.12%	9.21%	10.48%		10.06%

NORTH AMERICAN ELECTRIC PROXY GROUP

Company	Ticker	Constant Growth DCF	Multi-Stage DCF	Average CAPM	Risk Premium	Average ROE
Algonquin Power and Utilities	AQN	14.49%	11.13%	10.45%		12.02%
Canadian Utilities Limited	CU	8.91%	9.25%	9.68%		9.28%
Emera Inc.	EMA	10.65%	9.35%	8.52%		9.50%
Hydro One, Ltd.	H	7.91%	7.62%	8.12%		7.88%
ALLETE, Inc.	ALE	9.55%	9.09%	10.27%	10.01%	9.73%
Alliant Energy Corporation	LNT	8.96%	7.86%	9.92%	10.01%	9.19%
Duke Energy Corporation	DUK	10.10%	9.04%	9.69%	10.01%	9.71%
Edison International	EIX	8.92%	9.14%	10.56%	10.01%	9.66%
Entergy Corporation	ETR	7.26%	8.20%	10.69%	10.01%	9.04%
Evergy Inc	EVRG	10.12%	8.72%	10.36%	10.01%	9.80%
IDACORP, Inc.	IDA	7.31%	7.37%	9.67%	10.01%	8.59%
NextEra Energy, Inc.	NEE	11.44%	7.34%	10.25%	10.01%	9.76%
OGE Energy Corporation	OGE	8.08%	9.01%	11.38%	10.01%	9.62%
Portland General Electric Company	POR	11.00%	8.81%	10.14%	10.01%	9.99%
MEAN		9.62%	8.71%	9.98%	10.01%	9.56%
Flotation		0.50%	0.50%	0.50%		0.50%
MEAN (including flotation		10.12%	9.21%	10.48%		10.06%

Canadian & U.S. Macroeconomic Factors

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[11]	[12]	[13]	[14]
	Total Return on:		Total Return on:		Real GDP Growth		CPI Change		10-year Gov't Bond		Exports		Unemployment		Currency Exchange Rate (CAD / USD)
	S&P/TSX	S&P 500	S&P/TSX Utilities	S&P 500 Utilities	Canada	U.S.	Canada	U.S.	Canada	U.S.	Canada to U.S./ Canadian GDP	U.S. to Canada / U.S. GDP	Canada	U.S.	
1990	-18.7	-4.9	-1.6	-1.4	0.2	1.9	4.8	5.4	10.7	8.5		1.4	8.2	5.6	1.17
1991	8.4	31.9	-3.5	25.0	-2.1	-0.1	5.6	4.2	9.5	7.9		1.4	10.3	6.9	1.15
1992	-4.1	7.6	2.1	7.2	0.9	3.5	1.5	3.0	8.1	7.0		1.4	11.2	7.5	1.21
1993	32.2	10.1	16.3	13.4	2.7	2.8	1.9	3.0	7.2	5.9		1.5	11.4	6.9	1.29
1994	-1.3	1.2	3.8	-11.1	4.5	4.0	0.2	2.6	8.4	7.1		1.6	10.4	6.1	1.37
1995	15.1	37.6	-2.0	32.0	2.7	2.7	2.1	2.8	8.2	6.6		1.7	9.5	5.6	1.37
1996	26.7	22.0	17.5	5.2	1.6	3.8	1.6	3.0	7.2	6.4		1.7	9.6	5.4	1.36
1997	15.3	34.0	32.1	25.7	4.3	4.4	1.6	2.3	6.1	6.3	26.7	1.8	9.1	4.9	1.38
1998	-2.0	27.9	-0.2	15.3	3.9	4.5	1.0	1.6	5.3	5.3	28.6	1.7	8.3	4.5	1.48
1999	30.4	21.1	-30.8	-9.2	5.2	4.8	1.7	2.2	5.6	5.6	30.6	1.7	7.6	4.2	1.49
2000	10.1	-4.6	42.1	61.2	5.2	4.1	2.7	3.4	5.9	6.0	32.3	1.7	6.8	4.0	1.49
2001	-9.3	-9.3	7.3	-27.8	1.8	1.0	2.5	2.8	5.5	5.0	30.6	1.5	7.2	4.7	1.55
2002	-11.9	-22.6	3.4	-30.9	3.0	1.7	2.3	1.6	5.3	4.6	29.0	1.5	7.7	5.8	1.57
2003	24.2	24.5	23.4	23.3	1.8	2.9	2.8	2.3	4.8	4.0	26.1	1.5	7.6	6.0	1.40
2004	13.4	11.2	8.7	24.3	3.1	3.8	1.9	2.7	4.6	4.3	26.1	1.6	7.2	5.5	1.30
2005	25.4	7.0	37.6	19.2	3.2	3.5	2.2	3.4	4.1	4.3	25.8	1.6	6.8	5.1	1.21
2006	15.5	13.9	5.8	18.7	2.6	2.9	2.0	3.2	4.2	4.8	24.1	1.7	6.3	4.6	1.13
2007	11.6	5.7	11.8	18.9	2.1	1.9	2.1	2.8	4.3	4.6	22.5	1.7	6.1	4.6	1.07
2008	-33.5	-36.1	-20.4	-28.0	1.0	-0.3	2.4	3.8	3.6	3.6	22.3	1.8	6.2	5.8	1.07
2009	31.3	22.6	15.9	9.4	-2.9	-2.4	0.3	-0.4	3.2	3.2	17.2	1.4	8.4	9.3	1.14
2010	16.3	13.2	18.6	5.2	3.1	2.4	1.8	1.6	3.2	3.2	17.7	1.7	8.1	9.6	1.03
2011	-8.5	1.1	6.0	18.7	3.1	1.8	2.9	3.2	2.8	2.8	18.6	1.8	7.6	8.9	0.99
2012	4.9	14.2	3.3	3.0	1.8	2.2	1.5	2.1	1.9	1.8	18.4	1.8	7.4	8.1	1.00
2013	12.0	29.1	-4.9	11.2	2.3	1.8	0.9	1.5	2.3	2.3	18.8	1.8	7.1	7.4	1.03
2014	10.7	14.7	16.2	31.0	2.9	2.3	1.9	1.6	2.2	2.5	20.1	1.8	7.0	6.2	1.10
2015	-9.2	1.4	-4.4	-5.4	0.7	3.1	1.1	0.1	1.5	2.1	19.9	1.5	6.9	5.3	1.28
2016	21.9	13.7	18.7	16.6	1.0	1.7	1.4	1.3	1.3	1.8	19.4	1.4	7.1	4.9	1.33
2017	8.3	20.8	10.9	9.1	3.0	2.4	1.6	2.1	1.8	2.3	19.2	1.4	6.4	4.5	1.30
2018	-8.9	-4.4	-8.9	4.1	2.4	3.0	2.3	2.4	2.3	2.9	19.5	1.5	5.9	4.0	1.30
2019	23.5	31.8	38.2	25.7	1.9	2.4	1.9	1.8	1.6	2.1	19.3	1.4	5.7	3.8	1.33
2020	5.6	18.4	15.3	0.5	-6.2	-3.4	0.7	1.2	0.8	0.9	n/a	1.2	9.6	8.4	1.34
25-year Avg.	8.96	10.85	10.52	9.81	2.07	2.24	1.81	2.15	3.65	3.72	23.16	1.61	7.34	5.82	1.27
10-year Avg.	6.03	14.07	9.03	11.46	1.29	1.71	1.64	1.73	1.84	2.16	19.24	1.57	7.06	6.13	1.20
5-year Avg.	10.06	16.06	14.83	11.21	0.43	1.20	1.59	1.78	1.53	2.02	19.35	1.38	6.94	5.11	1.32
Correlation	0.76		0.66		0.88		0.76		0.98		0.14		0.46		--
Consensus Forecasts [15]															
2022					4.10	4.10	2.70	3.40	1.90	2.10					
2023					2.50	2.50	2.20	2.50	2.30	2.60					
2024					2.10	2.10	2.10	2.40	2.60	2.90					

Notes:
[1] Source:Bloomberg Professional; total return index gross dividend yield
[2] Source:Bloomberg Professional; total return index gross dividend yield
[3] Source:Bloomberg Professional; total return index gross dividend yield
[4] Source:Bloomberg Professional; total return index gross dividend yield
[5] Source: Statistics Canada. Table 36-10-0104-01 Gross domestic product, expenditure-based, Canadc
[6] Source: Bureau of Economic Analysis, Table 1.1.5. Gross Domestic Product
[7] Source: Statistics Canada; Consumer Price Index (2002=100), All items, not seasonally adjusted, accessed February 26, 2021
[8] Source: U.S. Bureau of Labor Statistics; CPI-All Urban Consumers (1982-84=100), all items, not seasonally adjusted, accessed February 26, 2021
[9] Source: Bank of Canada
[10] Source: Bloomberg Professional
[11] Source: Statistics Canada, Imports, exports and trade balance of goods by country and Gross domestic product, expenditure-based
United States Census Bureau (https://www.census.gov/foreign-trade/balance/c1220.html); Bureau of Economic Analysis; Table 1.1.5
[12] Source: Statistics Canada; Labour force survey estimates (LFS), unemployment rate, 15 years and over, seasonally adjusted, accessed February 26, 2021
[13] Source: U.S. Bureau of Labor Statistics, Unemployment Rate, seasonally adjusted, accessed February 26, 2021
[14] Source: Federal Reserve Economic Data, as of February 22, 2021
[15] Source: Consensus Forecasts, Survey Date October 11, 2021

CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	S&P Rating	Pays Dividends (Yes/No)	Postive Earnings Growth by more than one Analyst (Yes/No)	Market Cap (C$ Million)	Total Electric Customers	Total Revenue (C$ Million)	Total Assets (C$ Million)	Regulated Income / Total Income (%)	Regulated Electric Income / Total Regulated Income (%)	Involved in Merger (Yes/No)
Algonquin Power and Utilities	AQN	BBB	Yes	Yes	12,323	303,400	2,865	21,242	86%	N/A	Yes
AltaGas Inc.	ALA	BBB-	Yes	Yes	7,829.73	NA	10,573	21,593	140%	N/A	No
Canadian Utilities Limited	CU	A-	Yes	Yes	9,514	261,370	3,515	21,075	64%	N/A	No
Emera Inc.	EMA	BBB	Yes	Yes	15,488	1,533,300	5,765	34,244	92%	N/A	No
Enbridge Inc.	ENB	BBB+	Yes	Yes	110,959	NA	47,071	168,864	16%	N/A	No
Hydro One, Ltd.	H	A-	Yes	Yes	18,728	1,476,491	7,225	30,383	100%	N/A	No

Notes:
[1] Source: SNL Financial
[2] Source: Bloomberg Professional
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: Bloomberg Professional as of February 28, 2022
[5] Source: SNL Financial, as of 12/31/2021
[6] Source: SNL Financial, as of 12/31/2021
[7] Source: SNL Financial, as of 12/31/2021
[8] Source: Company 10-K reports, average of three most recent years
[9] Source: Company 10-K reports, average of three most recent years
[10] Source: Bloomberg Professional

U.S. ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	S&P Rating	Pays Dividends (Yes/No)	Postive Earnings Growth by more than one Analyst (Yes/No)	Market Cap (US$ Million)	Total Electric Customers	Total Revenue ($ Million)	Total Assets ($ Million)	Regulated Income / Total Income (%)	Regulated Electric Income / Total Regulated Income (%)	Involved in Merger (Yes/No)
ALLETE, Inc.	ALE	BBB	Yes	Yes	3,351	165,000	1,419	6,435	89%	97%	No
Alliant Energy Corporation	LNT	A-	Yes	Yes	14,628	981,570	3,669	18,553	96%	91%	No
Duke Energy Corporation	DUK	BBB+	Yes	Yes	77,215	8,062,606	24,677	169,587	99%	91%	No
Edison International	EIX	BBB	Yes	Yes	24,144	5,201,000	14,905	74,745	90%	100%	No
Entergy Corporation	ETR	BBB+	Yes	Yes	21,361	2,984,406	11,743	59,454	100%	99%	No
Evergy Inc	EVRG	A-	Yes	Yes	14,167	1,640,800	5,587	28,521	100%	100%	No
IDACORP, Inc.	IDA	BBB	Yes	Yes	5,252	603,753	1,458	7,211	100%	100%	No
NextEra Energy, Inc.	NEE	A-	Yes	Yes	153,624	5,607,675	17,069	140,912	76%	100%	No
OGE Energy Corporation	OGE	BBB+	Yes	Yes	7,518	879,447	3,654	12,606	100%	100%	Yes
Portland General Electric Company	POR	BBB+	Yes	Yes	4,540	917,000	2,396	9,494	100%	100%	No
Average									95%	98%	

Notes:
[1] Source: SNL Financial
[2] Source: Bloomberg Professional
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: Bloomberg Professional as of February 28, 2022
[5] Source: SNL Financial, as of 12/31/2021
[6] Source: SNL Financial, as of 12/31/2021
[7] Source: SNL Financial, as of 12/31/2021
[8] - [9] Source: Company 10-K reports, average of three most recent years
[10] Source: Bloomberg Professional

NORTH AMERICA ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	S&P Rating	Pays Dividends (Yes/No)	Postive Earnings Growth by more than one Analyst (Yes/No)	Market Cap ($ Million)	Total Electric Customers	Total Revenue ($ Million)	Total Assets ($ Million)	Regulated Income / Total Income (%)	Regulated Electric Income / Total Regulated Income (%)	Involved in Merger (Yes/No)
Algonquin Power and Utilities	AQN	BBB	Yes	Yes	12,323	303,400	2,865	21,242	86%	N/A	Yes
Canadian Utilities Limited	CU	A-	Yes	Yes	9,514	261,370	3,515	21,075	64%	N/A	No
Emera Inc.	EMA	BBB	Yes	Yes	15,488	1,533,300	5,765	34,244	92%	N/A	No
Hydro One, Ltd.	H	A-	Yes	Yes	18,728	1,476,491	7,225	30,383	100%	N/A	No
ALLETE, Inc.	ALE	BBB	Yes	Yes	3,351	165,000	1,419	6,435	89%	97%	No
Alliant Energy Corporation	LNT	A-	Yes	Yes	14,628	981,570	3,669	18,553	96%	91%	No
Duke Energy Corporation	DUK	BBB+	Yes	Yes	77,215	8,062,606	24,677	169,587	99%	91%	No
Edison International	EIX	BBB	Yes	Yes	24,144	5,201,000	14,905	74,745	90%	100%	No
Entergy Corporation	ETR	BBB+	Yes	Yes	21,361	2,984,406	11,743	59,454	100%	99%	No
Evergy Inc	EVRG	A-	Yes	Yes	14,167	1,640,800	5,587	28,521	100%	100%	No
IDACORP, Inc.	IDA	BBB	Yes	Yes	5,252	603,753	1,458	7,211	100%	100%	No
NextEra Energy, Inc.	NEE	A-	Yes	Yes	153,624	5,607,675	17,069	140,912	76%	100%	No
OGE Energy Corporation	OGE	BBB+	Yes	Yes	7,518	879,447	3,654	12,606	100%	100%	Yes
Portland General Electric Company	POR	BBB+	Yes	Yes	4,540	917,000	2,396	9,494	100%	100%	No

Notes:
[1] Source: SNL Financial
[2] Source: Bloomberg Professional
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: Bloomberg Professional as of February 28, 2022
[5] Source: SNL Financial, as of 12/31/2021
[6] Source: SNL Financial, as of 12/31/2021
[7] Source: SNL Financial, as of 12/31/2021
[8] Source: Company 10-K reports, average of three most recent years
[9] Source: Company 10-K reports, average of three most recent years
[10] Source: Bloomberg Professional

90-DAY CONSTANT GROWTH DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Algonquin Power & Utilities Corp.	AQN	$0.68	$14.13	4.83%	5.06%	8.70%	8.52%	n/a	11.08%	9.43%	13.55%	14.49%	16.18%
AltaGas Ltd.	ALA	$1.00	$26.22	3.81%	3.97%	n/a	10.74%	n/a	5.84%	8.29%	9.76%	12.26%	14.76%
Canadian Utilities Limited	CU	$1.78	$35.53	5.00%	5.10%	n/a	4.23%	n/a	3.40%	3.82%	8.49%	8.91%	9.34%
Enbridge Inc	ENB	$3.44	$51.34	6.70%	6.98%	6.00%	8.27%	8.50%	10.40%	8.29%	12.90%	15.27%	17.45%
Emera Inc.	EMA	$2.65	$59.76	4.43%	4.57%	n/a	7.13%	5.00%	6.12%	6.08%	9.55%	10.65%	11.72%
Hydro One Ltd.	H	$1.07	$31.43	3.39%	3.46%	n/a	4.60%	n/a	4.28%	4.44%	7.74%	7.91%	8.07%
MEAN				4.69%	4.86%	7.35%	7.25%	6.75%	6.85%	6.73%	10.33%	11.58%	12.92%
Flotation Costs [13]											0.50%	0.50%	0.50%
											10.83%	12.08%	13.42%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of February 28, 2022
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [10])
[5] Source: Zacks at February 28, 2022
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of February 28, 2022
[7] Source: Value Line
[8] Yahoo! Finance as of February 28, 2022
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])
[13] Flotation cost adjustment for equity issuance costs, administrative costs, impact of underpricing, potential for dilution, and equity cushion for investors.

90-DAY CONSTANT GROWTH DCF -- U.S. ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
ALLETE, Inc.	ALE	$2.60	$63.37	4.10%	4.21%	n/a	5.33%	5.00%	5.67%	5.33%	9.21%	9.55%	9.89%
Alliant Energy Corporation	LNT	$1.71	$58.17	2.94%	3.03%	6.10%	6.04%	5.50%	6.10%	5.93%	8.52%	8.96%	9.13%
Duke Energy Corporation	DUK	$3.94	$101.92	3.87%	3.98%	6.00%	5.56%	7.00%	5.90%	6.11%	9.53%	10.10%	11.00%
Edison International	EIX	$2.80	$63.96	4.38%	4.47%	3.70%	3.83%	NMF	5.80%	4.44%	8.16%	8.92%	10.30%
Entergy Corporation	ETR	$4.04	$106.97	3.78%	3.84%	1.00%	3.67%	3.00%	6.00%	3.42%	4.80%	7.26%	9.89%
Evergy Inc	EVRG	$2.29	$65.04	3.52%	3.64%	6.10%	6.72%	8.00%	5.12%	6.49%	8.73%	10.12%	11.66%
IDACORP, Inc.	IDA	$3.00	$107.47	2.79%	2.85%	4.30%	5.11%	4.00%	4.40%	4.45%	6.85%	7.31%	7.98%
NextEra Energy, Inc.	NEE	$1.70	$84.15	2.02%	2.11%	8.80%	8.45%	11.00%	9.07%	9.33%	10.55%	11.44%	13.13%
OGE Energy Corporation	OGE	$1.64	$36.24	4.53%	4.60%	3.50%	4.51%	4.00%	1.90%	3.48%	6.47%	8.08%	9.14%
Portland General Electric Company	POR	$1.72	$50.96	3.38%	3.50%	4.60%	5.80%	7.00%	12.60%	7.50%	8.05%	11.00%	16.19%
MEAN				3.53%	3.62%	4.90%	5.50%	6.06%	6.26%	5.65%	8.09%	9.27%	10.83%
Flotation Costs [13]											0.50%	0.50%	0.50%
											8.59%	9.77%	11.33%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of February 28, 2022
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [10])
[5] Source: Zacks at February 28, 2022
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of February 28, 2022
[7] Source: Value Line
[8] Yahoo! Finance as of February 28, 2022
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])
[13] Flotation cost adjustment for equity issuance costs, administrative costs, impact of underpricing, potential for dilution, and equity cushion for investors.

90-DAY CONSTANT GROWTH DCF -- NORTH AMERICAN ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Algonquin Power and Utilities	AQN	$0.68	$14.13	4.83%	5.06%	8.70%	8.52%	n/a	11.08%	9.43%	13.55%	14.49%	16.18%
Canadian Utilities Limited	CU	$1.78	$35.53	5.00%	5.10%	n/a	4.23%	n/a	3.40%	3.82%	8.49%	8.91%	9.34%
Emera Inc.	EMA	$2.65	$59.76	4.43%	4.57%	n/a	7.13%	5.00%	6.12%	6.08%	9.55%	10.65%	11.72%
Hydro One, Ltd.	H	$1.07	$31.43	3.39%	3.46%	n/a	4.60%	n/a	4.28%	4.44%	7.74%	7.91%	8.07%
ALLETE, Inc.	ALE	$2.60	$63.37	4.10%	4.21%	n/a	5.33%	5.00%	5.67%	5.33%	9.21%	9.55%	9.89%
Alliant Energy Corporation	LNT	$1.71	$58.17	2.94%	3.03%	6.10%	6.04%	5.50%	6.10%	5.93%	8.52%	8.96%	9.13%
Duke Energy Corporation	DUK	$3.94	$101.92	3.87%	3.98%	6.00%	5.56%	7.00%	5.90%	6.11%	9.53%	10.10%	11.00%
Edison International	EIX	$2.80	$63.96	4.38%	4.47%	3.70%	3.83%	NMF	5.80%	4.44%	8.16%	8.92%	10.30%
Entergy Corporation	ETR	$4.04	$106.97	3.78%	3.84%	1.00%	3.67%	3.00%	6.00%	3.42%	4.80%	7.26%	9.89%
Evergy Inc	EVRG	$2.29	$65.04	3.52%	3.64%	6.10%	6.72%	8.00%	5.12%	6.49%	8.73%	10.12%	11.66%
IDACORP, Inc.	IDA	$3.00	$107.47	2.79%	2.85%	4.30%	5.11%	4.00%	4.40%	4.45%	6.85%	7.31%	7.98%
NextEra Energy, Inc.	NEE	$1.70	$84.15	2.02%	2.11%	8.80%	8.45%	11.00%	9.07%	9.33%	10.55%	11.44%	13.13%
OGE Energy Corporation	OGE	$1.64	$36.24	4.53%	4.60%	3.50%	4.51%	4.00%	1.90%	3.48%	6.47%	8.08%	9.14%
Portland General Electric Company	POR	$1.72	$50.96	3.38%	3.50%	4.60%	5.80%	7.00%	12.60%	7.50%	8.05%	11.00%	16.19%
MEAN				3.78%	3.89%	5.28%	5.68%	5.95%	6.25%	5.73%	8.59%	9.62%	10.97%
Flotation Costs [13]											0.50%	0.50%	0.50%
											9.09%	10.12%	11.47%

Notes:

[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of February 28, 2022
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [10])
[5] Source: Zacks at February 28, 2022
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of February 28, 2022
[7] Source: Value Line
[8] Yahoo! Finance as of February 28, 2022
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])
[13] Flotation cost adjustment for equity issuance costs, administrative costs, impact of underpricing, potential for dilution, and equity cushion for investors.

90-DAY MULTI-STAGE DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Algonquin Power & Utilities Corp.	AQN	$0.68	$14.13	9.43%	8.50%	7.57%	6.63%	5.70%	4.77%	3.84%	11.13%
AltaGas Ltd.	ALA	$1.00	$26.22	8.29%	7.55%	6.81%	6.06%	5.32%	4.58%	3.84%	9.25%
Canadian Utilities Limited	CU	$1.78	$35.53	3.82%	3.82%	3.82%	3.83%	3.83%	3.83%	3.84%	9.25%
Enbridge Inc	ENB	$3.44	$51.34	8.29%	7.55%	6.81%	6.06%	5.32%	4.58%	3.84%	13.27%
Emera Inc.	EMA	$2.65	$59.76	6.08%	5.71%	5.33%	4.96%	4.59%	4.21%	3.84%	9.35%
Hydro One Ltd.	H	$1.07	$31.43	4.44%	4.34%	4.24%	4.14%	4.04%	3.94%	3.84%	7.62%
MEAN				6.73%	6.24%	5.76%	5.28%	4.80%	4.32%	3.84%	9.98%
Flotation Costs [11]											0.50%
											10.48%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of February 28, 2022
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, October 11, 2021, at 28 estimates for 2027-2031 = (GDP x (1+ CPI))+CPI
[10] Internal rate of return
[11] Flotation cost adjustment for equity issuance costs, administrative costs, impact of underpricing, potential for dilution, and equity cushion for investors.

90-DAY MULTI-STAGE DCF -- U.S. ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
ALLETE, Inc.	ALE	$2.60	$63.37	5.33%	5.17%	5.00%	4.84%	4.68%	4.51%	4.35%	9.09%
Alliant Energy Corporation	LNT	$1.71	$58.17	5.93%	5.67%	5.41%	5.14%	4.88%	4.61%	4.35%	7.86%
Duke Energy Corporation	DUK	$3.94	$101.92	6.11%	5.82%	5.53%	5.23%	4.94%	4.64%	4.35%	9.04%
Edison International	EIX	$2.80	$63.96	4.44%	4.43%	4.41%	4.39%	4.38%	4.36%	4.35%	9.14%
Entergy Corporation	ETR	$4.04	$106.97	3.42%	3.57%	3.73%	3.88%	4.04%	4.19%	4.35%	8.20%
Evergy Inc	EVRG	$2.29	$65.04	6.49%	6.13%	5.77%	5.42%	5.06%	4.70%	4.35%	8.72%
IDACORP, Inc.	IDA	$3.00	$107.47	4.45%	4.44%	4.42%	4.40%	4.38%	4.36%	4.35%	7.37%
NextEra Energy, Inc.	NEE	$1.70	$84.15	9.33%	8.50%	7.67%	6.84%	6.01%	5.18%	4.35%	7.34%
OGE Energy Corporation	OGE	$1.64	$36.24	3.48%	3.62%	3.77%	3.91%	4.06%	4.20%	4.35%	9.01%
Portland General Electric Company	POR	$1.72	$50.96	7.50%	6.97%	6.45%	5.92%	5.40%	4.87%	4.35%	8.81%
MEAN				5.65%	5.43%	5.21%	5.00%	4.78%	4.56%	4.35%	8.46%
Flotation Costs [11]											0.50%
											8.96%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of February 28, 2022
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, October 11, 2021, at 3 estimates for 2027-2031 = (GDP x (1+ CPI))+CPI
[10] Internal rate of return
[11] Flotation cost adjustment for equity issuance costs, administrative costs, impact of underpricing, potential for dilution, and equity cushion for investors.

90-DAY MULTI-STAGE DCF -- NORTH AMERICAN ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Algonquin Power and Utilities	AQN	$0.68	$14.13	9.43%	8.50%	7.57%	6.63%	5.70%	4.77%	3.84%	11.13%
Canadian Utilities Limited	CU	$1.78	$35.53	3.82%	3.82%	3.82%	3.83%	3.83%	3.83%	3.84%	9.25%
Emera Inc.	EMA	$2.65	$59.76	6.08%	5.71%	5.33%	4.96%	4.59%	4.21%	3.84%	9.35%
Hydro One, Ltd.	H	$1.07	$31.43	4.44%	4.34%	4.24%	4.14%	4.04%	3.94%	3.84%	7.62%
ALLETE, Inc.	ALE	$2.60	$63.37	5.33%	5.17%	5.00%	4.84%	4.68%	4.51%	4.35%	9.09%
Alliant Energy Corporation	LNT	$1.71	$58.17	5.93%	5.67%	5.41%	5.14%	4.88%	4.61%	4.35%	7.86%
Duke Energy Corporation	DUK	$3.94	$101.92	6.11%	5.82%	5.53%	5.23%	4.94%	4.64%	4.35%	9.04%
Edison International	EIX	$2.80	$63.96	4.44%	4.43%	4.41%	4.39%	4.38%	4.36%	4.35%	9.14%
Entergy Corporation	ETR	$4.04	$106.97	3.42%	3.57%	3.73%	3.88%	4.04%	4.19%	4.35%	8.20%
Evergy Inc	EVRG	$2.29	$65.04	6.49%	6.13%	5.77%	5.42%	5.06%	4.70%	4.35%	8.72%
IDACORP, Inc.	IDA	$3.00	$107.47	4.45%	4.44%	4.42%	4.40%	4.38%	4.36%	4.35%	7.37%
NextEra Energy, Inc.	NEE	$1.70	$84.15	9.33%	8.50%	7.67%	6.84%	6.01%	5.18%	4.35%	7.34%
OGE Energy Corporation	OGE	$1.64	$36.24	3.48%	3.62%	3.77%	3.91%	4.06%	4.20%	4.35%	9.01%
Portland General Electric Company	POR	$1.72	$50.96	7.50%	6.97%	6.45%	5.92%	5.40%	4.87%	4.35%	8.81%
MEAN				5.73%	5.48%	5.22%	4.97%	4.71%	4.46%	4.20%	8.71%
Flotation Costs [11]											0.50%
											9.21%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of February 28, 2022
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, October 11, 2021, at (3, 28), estimates for 2027-2031 = (GDP x (1+ CPI))+CPI
[10] Internal rate of return
[11] Flotation cost adjustment for equity issuance costs, administrative costs, impact of underpricing, potential for dilution, and equity cushion for investors.

Canadian Market DCF Calculation as of February 28, 2022

	[1]	[2]	[3]	[4]			[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return			Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX COMPOSITE INDEX	**3.16%**	**3.29%**	**7.96%**	**11.25%**			**2.84%**	**8.40%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Sun Life Financial Inc	SLF	586.0	66.66	39,066	1.68%	3.96%	20.10%	0.0667%	0.3386%
Enghouse Systems Ltd	ENGH	55.6	41.39	Excl.	Excl.	1.55%	n/a		
H&R Real Estate Investment Trust	HR-U	286.9	12.93	Excl.	Excl.	4.02%	n/a		
Ivanhoe Mines Ltd	IVN	1210.3	12.9	Excl.	Excl.	n/a	32.20%		
Sleep Country Canada Holdings Inc	ZZZ	36.9	29.87	Excl.	Excl.	2.61%	n/a		
West Fraser Timber Co Ltd	WFG	103.4	126.52	Excl.	Excl.	1.019%	n/a		
TELUS International CDA Inc	TIXT	66.0	31.17	Excl.	Excl.	n/a	18.32%		
Brookfield Asset Management Inc	BAM/A	1568.2	69.27	Excl.	Excl.	1.03%	n/a		
Ballard Power Systems Inc	BLDP	297.8	14.5	Excl.	Excl.	n/a	22.00%		
Energy Fuels Inc/Canada	EFR	156.3	10.43	Excl.	Excl.	n/a	n/a		
Saputo Inc	SAP	415.2	31.06	12,896	0.56%	2.32%	3.80%	0.0129%	0.0211%
Pembina Pipeline Corp	PPL	550.3	43.1	23,716	1.02%	5.85%	4.00%	0.0598%	0.0409%
Secure Energy Services Inc	SES	308.8	6.13	Excl.	Excl.	0.49%	n/a		
Ritchie Bros Auctioneers Inc	RBA	110.7	66.43	7,352	0.32%	1.91%	12.40%	0.0060%	0.0393%
Gildan Activewear Inc	GIL	190.1	49.76	9,459	0.41%	1.75%	47.13%	0.0071%	0.1922%
Descartes Systems Group Inc/The	DSG	84.8	90.32	Excl.	Excl.	n/a	18.80%		
Nuvei Corp	NVEI	66.9	68.81	Excl.	Excl.	n/a	n/a		
Richelieu Hardware Ltd	RCH	55.9	48.49	Excl.	Excl.	1.07%	n/a		
Lithium Americas Corp	LAC	134.0	36.2	Excl.	Excl.	n/a	n/a		
Innergex Renewable Energy Inc	INE	204.1	18.43	Excl.	Excl.	3.91%	n/a		
Manulife Financial Corp	MFC	1942.7	25.68	49,889	2.15%	5.14%	1.20%	0.1106%	0.0258%
Element Fleet Management Corp	EFN	402.4	12.44	Excl.	Excl.	2.49%	n/a		
FirstService Corp	FSV	44.0	180.44	Excl.	Excl.	0.58%	n/a		
Canadian Pacific Railway Ltd	CP	929.7	89.25	82,972	3.58%	0.85%	10.36%	0.0305%	0.3705%
Well Health Technologies Corp	WELL	208.2	4.53	Excl.	Excl.	n/a	n/a		
Baytex Energy Corp	BTE	564.2	5.79	Excl.	Excl.	n/a	n/a		
Crescent Point Energy Corp	CPG	577.0	9.07	Excl.	Excl.	1.98%	n/a		
Tricon Residential Inc	TCN	272.9	18.84	Excl.	Excl.	1.57%	n/a		
Sienna Senior Living Inc	SIA	67.0	15.44	Excl.	Excl.	6.06%	n/a		
Centerra Gold Inc	CG	297.1	12.36	3,672	0.16%	2.27%	-20.97%	0.0036%	-0.0332%
Intact Financial Corp	IFC	176.1	181.79	Excl.	Excl.	2.20%	n/a		
George Weston Ltd	WN	146.9	137.44	20,183	0.87%	1.75%	11.80%	0.0152%	0.1027%
iA Financial Corp Inc	IAG	107.6	75.31	Excl.	Excl.	3.32%	n/a		
MEG Energy Corp	MEG	307.0	16.55	Excl.	Excl.	n/a	n/a		
Hydro One Ltd	H	598.3	31.3	18,728	0.81%	3.40%	0.44%	0.0275%	0.0035%
PrairieSky Royalty Ltd	PSK	238.8	17.14	Excl.	Excl.	2.10%	n/a		
Cameco Corp	CCO	398.3	31.17	12,415	0.54%	0.38%	272.86%	0.0021%	1.4606%
Tilray Brands Inc	TLRY	466.5	7.7	Excl.	Excl.	n/a	n/a		
Turquoise Hill Resources Ltd	TRQ	201.2	26.07	Excl.	Excl.	n/a	n/a		
Canfor Corp	CFP	124.5	28.69	Excl.	Excl.	n/a	n/a		
Nutrien Ltd	NTR	551.3	109.01	60,097	2.59%	2.27%	-1.70%	0.0589%	-0.0441%
Cascades Inc	CAS	100.9	13.13	Excl.	Excl.	3.66%	n/a		
TransAlta Renewables Inc	RNW	266.9	17.45	4,657	0.20%	5.39%	20.25%	0.0108%	0.0407%
Interfor Corp	IFP	60.8	38.61	Excl.	Excl.	n/a	n/a		
Primo Water Corp	PRMW	159.6	18.43	2,942	0.13%	1.96%	11.25%	0.0025%	0.0143%
Brookfield Infrastructure Partners LP	BIP-U	305.2	75.22	Excl.	Excl.	3.66%	n/a		
Winpak Ltd	WPK	65.0	38.2	Excl.	Excl.	0.31%	n/a		
Franco-Nevada Corp	FNV	192.7	186.66	35,963	1.55%	0.88%	4.00%	0.0137%	0.0620%
Cenovus Energy Inc	CVE	1996.2	19.93	39,785	1.72%	0.70%	-23.52%	0.0121%	-0.4035%
NorthWest Healthcare Properties Real Estate Inve	NWH-U	217.9	13.57	Excl.	Excl.	5.90%	n/a		
Sprott Inc	SII	25.8	52.18	Excl.	Excl.	2.44%	n/a		
Pretium Resources Inc	PVG	187.9	18.49	Excl.	Excl.	n/a	n/a		
Empire Co Ltd	EMP/A	164.7	39.26	6,468	0.28%	1.53%	0.11%	0.0043%	0.0003%
Loblaw Cos Ltd	L	333.6	98.87	32,978	1.42%	1.48%	4.77%	0.0210%	0.0678%
Metro Inc/CN	MRU	241.2	66.16	15,958	0.69%	1.66%	8.76%	0.0114%	0.0602%

Canadian Market DCF Calculation as of February 28, 2022

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast Canadian Government Bond 30 Year	[14] Equity Risk Premium
S&P/TSX COMPOSITE INDEX	**3.16%**	**3.29%**	**7.96%**	**11.25%**	**2.84%**	**8.40%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price ($)	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Tourmaline Oil Corp	TOU	331.6	50	Excl.	Excl.	1.60%	n/a		
Bank of Montreal	BMO	648.5	144.73	93,851	4.05%	3.68%	4.94%	0.1487%	0.1999%
Bank of Nova Scotia/The	BNS	1204.4	91.85	110,624	4.77%	4.35%	4.94%	0.2077%	0.2354%
NexGen Energy Ltd	NXE	479.3	6.73	Excl.	Excl.	n/a	n/a		
Canadian Imperial Bank of Commerce	CM	451.0	160.43	72,348	3.12%	4.01%	3.21%	0.1252%	0.1000%
Canadian Western Bank	CWB	90.2	37.11	Excl.	Excl.	3.23%	n/a		
Laurentian Bank of Canada	LB	43.6	42.57	Excl.	Excl.	4.13%	n/a		
National Bank of Canada	NA	338.2	101.63	34,376	1.48%	3.42%	3.00%	0.0508%	0.0445%
Converge Technology Solutions Corp	CTS	214.9	9.45	Excl.	Excl.	n/a	n/a		
Toronto-Dominion Bank/The	TD	1818.8	102.28	186,026	8.02%	3.48%	5.17%	0.2792%	0.4143%
Equitable Group Inc	EQB	34.1	75.74	Excl.	Excl.	1.48%	n/a		
Osisko Gold Royalties Ltd	OR	166.4	15.65	2,604	0.11%	1.41%	24.17%	0.0016%	0.0271%
TMX Group Ltd	X	55.9	128.04	Excl.	Excl.	2.59%	n/a		
Sandstorm Gold Ltd	SSL	191.7	9.04	Excl.	Excl.	0.88%	n/a		
ERO Copper Corp	ERO	90.2	18.14	Excl.	Excl.	n/a	n/a		
Parex Resources Inc	PXT	119.2	27.95	Excl.	Excl.	2.00%	n/a		
Boralex Inc	BLX	102.6	37.01	Excl.	Excl.	1.78%	n/a		
Jamieson Wellness Inc	JWEL	40.4	32.85	Excl.	Excl.	1.83%	n/a		
Methanex Corp	MX	74.3	65.99	Excl.	Excl.	0.98%	n/a		
Restaurant Brands International Inc	QSR	309.9	70.95	21,987	0.95%	3.93%	8.70%	0.0372%	0.0824%
Constellation Software Inc/Canada	CSU	21.2	2136.16	Excl.	Excl.	0.24%	n/a		
Suncor Energy Inc	SU	1436.3	38.76	Excl.	Excl.	4.33%	n/a		
ECN Capital Corp	ECN	245.3	5.71	Excl.	Excl.	2.10%	n/a		
Seabridge Gold Inc	SEA	79.1	21.91	Excl.	Excl.	n/a	n/a		
Parkland Corp	PKI	155.1	33.17	Excl.	Excl.	3.72%	n/a		
LifeWorks Inc	LWRK	69.3	25.22	Excl.	Excl.	3.09%	n/a		
Canada Goose Holdings Inc	GOOS	56.0	33.18	Excl.	Excl.	n/a	29.50%		
Lundin Mining Corp	LUN	735.8	12.23	8,998	0.39%	2.94%	-20.21%	0.0114%	-0.0784%
Wesdome Gold Mines Ltd	WDO	141.6	14.27	Excl.	Excl.	n/a	n/a		
Boyd Group Services Inc	BYD	21.5	165.47	Excl.	Excl.	0.35%	n/a		
Cronos Group Inc	CRON	375.0	4.55	Excl.	Excl.	n/a	-25.99%		
Novagold Resources Inc	NG	332.9	8.87	Excl.	Excl.	n/a	n/a		
GFL Environmental Inc	GFL	326.2	37.06	Excl.	Excl.	0.15%	n/a		
Trisura Group Ltd	TSU	41.2	34.72	Excl.	Excl.	n/a	n/a		
Lightspeed Commerce Inc	LSPD	148.4	33.3	Excl.	Excl.	n/a	n/a		
Aecon Group Inc	ARE	60.8	17.61	Excl.	Excl.	3.98%	n/a		
Kinaxis Inc	KXS	27.5	145.31	Excl.	Excl.	n/a	n/a		
Tamarack Valley Energy Ltd	TVE	434.0	5.16	Excl.	Excl.	1.93%	n/a		
Atco Ltd/Canada	ACO/X	101.2	41.63	Excl.	Excl.	4.44%	n/a		
Dundee Precious Metals Inc	DPM	192.7	7.5	Excl.	Excl.	2.75%	n/a		
TFI International Inc	TFII	92.2	132.12	12,175	0.52%	1.04%	19.16%	0.0055%	0.1006%
Stella-Jones Inc	SJ	63.4	39.75	Excl.	Excl.	1.81%	n/a		
Royal Bank of Canada	RY	1417.5	140.21	198,751	8.57%	3.42%	4.02%	0.2934%	0.3445%
Crombie Real Estate Investment Trust	CRR-U	103.8	17.38	Excl.	Excl.	5.12%	n/a		
Russel Metals Inc	RUS	63.1	31.4	Excl.	Excl.	4.84%	n/a		
Stantec Inc	STN	111.4	62.99	Excl.	Excl.	1.14%	n/a		
Transcontinental Inc	TCL/A	73.0	20.45	Excl.	Excl.	4.40%	n/a		
Home Capital Group Inc	HCG	43.5	38.31	Excl.	Excl.	1.57%	n/a		
Capstone Mining Corp	CS	413.8	6.57	Excl.	Excl.	n/a	n/a		
Fortuna Silver Mines Inc	FVI	291.5	4.73	Excl.	Excl.	n/a	n/a		
Endeavour Silver Corp	EDR	170.5	5.35	Excl.	Excl.	n/a	2.24%		
Linamar Corp	LNR	65.5	66.19	Excl.	Excl.	1.21%	n/a		
Killam Apartment Real Estate Investment Trust	KMP-U	114.6	21.33	Excl.	Excl.	3.28%	n/a		
North West Co Inc/The	NWC	47.9	36.02	Excl.	Excl.	4.11%	n/a		
Celestica Inc	CLS	105.9	15.07	Excl.	Excl.	n/a	14.47%		

Canadian Market DCF Calculation as of February 28, 2022

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX COMPOSITE INDEX	**3.16%**	**3.29%**	**7.96%**	**11.25%**	**2.84%**	**8.40%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
SSR Mining Inc	SSRM	212.4	25.09	5,329	0.23%	1.42%	3.00%	0.0033%	0.0069%
Choice Properties Real Estate Investment Trust	CHP-U	327.5	14.52	Excl.	Excl.	5.10%	n/a		
BlackBerry Ltd	BB	574.8	8.7	Excl.	Excl.	n/a	22.10%		
Silvercorp Metals Inc	SVM	177.1	4.7	Excl.	Excl.	0.68%	n/a		
Granite Real Estate Investment Trust	GRT-U	65.7	93.87	Excl.	Excl.	3.30%	n/a		
Toromont Industries Ltd	TIH	82.4	107.44	Excl.	Excl.	1.45%	n/a		
First Majestic Silver Corp	FR	260.1	14.27	Excl.	Excl.	0.17%	n/a		
Advantage Energy Ltd	AAV	190.8	7.41	Excl.	Excl.	n/a	n/a		
Colliers International Group Inc	CIGI	42.7	174.05	Excl.	Excl.	0.22%	n/a		
Cogeco Communications Inc	CCA	30.8	101.2	3,118	0.13%	2.79%	4.06%	0.0037%	0.0055%
First Capital Real Estate Investment Trust	FCR-U	219.2	18.15	Excl.	Excl.	2.38%	n/a		
First Quantum Minerals Ltd	FM	691.2	37.17	25,690	1.11%	0.03%	4.84%	0.0003%	0.0536%
Rogers Communications Inc	RCI/B	393.8	65.49	25,788	1.11%	3.05%	9.71%	0.0340%	0.1079%
Shopify Inc	SHOP	114.0	879.92	Excl.	Excl.	n/a	49.50%		
Mullen Group Ltd	MTL	94.2	12.36	Excl.	Excl.	4.85%	n/a		
NFI Group Inc	NFI	77.1	18.96	Excl.	Excl.	4.48%	n/a		
Maple Leaf Foods Inc	MFI	124.8	26.7	Excl.	Excl.	3.00%	n/a		
Hudbay Minerals Inc	HBM	261.6	10.33	2,702	0.12%	0.19%	-18.80%	0.0002%	-0.0219%
Stelco Holdings Inc	STLC	72.9	38.91	Excl.	Excl.	3.08%	n/a		
Labrador Iron Ore Royalty Corp	LIF	64.0	46.82	Excl.	Excl.	9.82%	n/a		
Dream Office Real Estate Investment Trust	D-U	48.3	26.14	Excl.	Excl.	3.83%	n/a		
CCL Industries Inc	CCL/B	168.4	57.14	Excl.	Excl.	1.68%	n/a		
Superior Plus Corp	SPB	176.0	11.43	Excl.	Excl.	6.30%	n/a		
Freehold Royalties Ltd	FRU	150.6	14.15	Excl.	Excl.	5.09%	n/a		
Westshore Terminals Investment Corp	WTE	63.3	29.71	Excl.	Excl.	3.37%	n/a		
Northland Power Inc	NPI	227.1	40.3	Excl.	Excl.	2.98%	n/a		
Denison Mines Corp	DML	814.6	1.9	Excl.	Excl.	n/a	n/a		
Canadian Apartment Properties REIT	CAR-U	173.3	52.76	Excl.	Excl.	2.75%	n/a		
Peyto Exploration & Development Corp	PEY	168.7	10.94	Excl.	Excl.	5.48%	n/a		
Algonquin Power & Utilities Corp	AQN	671.9	18.34	12,323	0.53%	4.76%	8.67%	0.0253%	0.0461%
Dye & Durham Ltd	DND	68.2	29.27	Excl.	Excl.	0.26%	n/a		
SmartCentres Real Estate Investment Trust	SRU-U	144.0	31.81	Excl.	Excl.	5.82%	n/a		
Pan American Silver Corp	PAAS	210.5	29.98	6,310	0.27%	2.04%	4.55%	0.0055%	0.0124%
AltaGas Ltd	ALA	280.4	27.92	7,830	0.34%	3.80%	10.03%	0.0128%	0.0339%
Altus Group Ltd/Canada	AIF	44.8	49.12	Excl.	Excl.	1.22%	n/a		
Cominar Real Estate Investment Trust	CUF-U	182.5	11.7	Excl.	Excl.	3.08%	n/a		
Corus Entertainment Inc	CJR/B	204.8	5.08	Excl.	Excl.	4.72%	n/a		
Emera Inc	EMA	261.2	59.3	15,488	0.67%	4.47%	7.50%	0.0298%	0.0501%
Summit Industrial Income REIT	SMU-U	175.4	21.53	Excl.	Excl.	2.62%	n/a		
Birchcliff Energy Ltd	BIR	265.3	6.74	Excl.	Excl.	0.59%	n/a		
Primaris REIT	PMZ-U	98.3	14.3	Excl.	Excl.	5.60%	n/a		
Torex Gold Resources Inc	TXG	85.8	16.08	Excl.	Excl.	n/a	n/a		
Lion Electric Co/The	LEV	190.0	10.26	Excl.	Excl.	n/a	n/a		
Waste Connections Inc	WCN	257.3	156.5	40,273	1.74%	0.75%	12.78%	0.0130%	0.2219%
Allied Properties Real Estate Investment Trust	AP-U	127.3	44.08	Excl.	Excl.	3.97%	n/a		
Park Lawn Corp	PLC	33.9	35.52	Excl.	Excl.	1.28%	n/a		
Keyera Corp	KEY	214.1	29.69	6,357	0.27%	6.47%	9.00%	0.0177%	0.0247%
Barrick Gold Corp	ABX	1779.3	28.65	50,978	2.20%	1.78%	2.00%	0.0391%	0.0440%
BCE Inc	BCE	909.1	66.57	60,516	2.61%	5.53%	5.84%	0.1442%	0.1524%
Chartwell Retirement Residences	CSH-U	232.0	12.17	Excl.	Excl.	5.03%	n/a		
Premium Brands Holdings Corp	PBH	44.8	116.92	Excl.	Excl.	2.17%	n/a		
Equinox Gold Corp	EQX	302.2	8.99	Excl.	Excl.	n/a	n/a		
Artis Real Estate Investment Trust	AX-U	123.7	13	Excl.	Excl.	4.62%	n/a		
Hut 8 Mining Corp	HUT	169.6	7.76	Excl.	Excl.	n/a	n/a		
TC Energy Corp	TRP	980.8	68.1	66,794	2.88%	5.29%	3.90%	0.1522%	0.1123%

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S&P/TSX COMPOSITE INDEX	**3.16%**	**3.29%**	**7.96%**	**11.25%**	**2.84%**	**8.40%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
OceanaGold Corp	OGC	704.2	2.39	Excl.	Excl.	n/a	113.85%		
B2Gold Corp	BTO	1056.6	5.12	5,410	0.23%	4.03%	-0.93%	0.0094%	-0.0022%
Bausch Health Cos Inc	BHC	359.6	30.49	Excl.	Excl.	n/a	5.54%		
Dollarama Inc	DOL	292.8	65.5	19,179	0.83%	0.31%	16.13%	0.0025%	0.1334%
Capital Power Corp	CPX	116.2	38.95	Excl.	Excl.	5.62%	n/a		
Eldorado Gold Corp	ELD	182.7	13.92	Excl.	Excl.	n/a	5.00%		
Onex Corp	ONEX	86.8	85.12	Excl.	Excl.	0.47%	n/a		
Imperial Oil Ltd	IMO	669.1	56.89	Excl.	Excl.	2.39%	n/a		
Air Canada	AC	357.8	23.95	Excl.	Excl.	n/a	169.94%		
ATS Automation Tooling Systems Inc	ATA	92.3	49.15	Excl.	Excl.	n/a	n/a		
Brookfield Renewable Partners LP	BEP-U	275.1	45.56	Excl.	Excl.	3.58%	n/a		
Docebo Inc	DCBO	32.9	66.66	Excl.	Excl.	n/a	n/a		
Exchange Income Corp	EIF	38.1	40.65	Excl.	Excl.	5.61%	n/a		
Agnico Eagle Mines Ltd	AEM	454.8	64.03	29,119	1.26%	3.22%	1.00%	0.0405%	0.0126%
Bombardier Inc	BBD/B	2132.8	1.58	Excl.	Excl.	n/a	n/a		
Topaz Energy Corp	TPZ	138.9	19.86	Excl.	Excl.	4.83%	n/a		
TELUS Corp	T	1375.8	32.01	44,039	1.90%	4.09%	13.97%	0.0777%	0.2652%
Aritzia Inc	ATZ	89.0	48.19	Excl.	Excl.	n/a	96.31%		
InterRent Real Estate Investment Trust	IIP-U	139.4	15.4	Excl.	Excl.	2.22%	n/a		
CAE Inc	CAE	317.0	33.91	Excl.	Excl.	n/a	10.00%		
Canadian Natural Resources Ltd	CNQ	1167.3	70.81	82,660	3.56%	3.32%	14.04%	0.1183%	0.5004%
Canadian Tire Corp Ltd	CTC/A	56.4	186.87	10,544	0.45%	2.78%	16.50%	0.0127%	0.0750%
Spin Master Corp	TOY	31.8	46.42	Excl.	Excl.	n/a	33.50%		
Canadian Utilities Ltd	CU	197.0	35.3	Excl.	Excl.	5.03%	n/a		
Brookfield Business Partners LP	BBU-U	77.8	54.44	Excl.	Excl.	0.59%	n/a		
CGI Inc	GIB/A	216.9	103.92	Excl.	Excl.	n/a	8.60%		
New Gold Inc	NGD	681.3	2.19	Excl.	Excl.	n/a	5.00%		
Fairfax Financial Holdings Ltd	FFH	25.0	614.45	15,353	0.66%	2.03%	44.70%	0.0135%	0.2959%
Finning International Inc	FTT	157.7	36.88	5,817	0.25%	2.44%	10.00%	0.0061%	0.0251%
Badger Infrastructure Solutions Ltd	BDGI	34.5	30.38	Excl.	Excl.	2.07%	n/a		
Canaccord Genuity Group Inc	CF	105.9	12.91	Excl.	Excl.	2.63%	n/a		
Fortis Inc/Canada	FTS	474.9	58.08	27,580	1.19%	3.68%	6.40%	0.0438%	0.0761%
BRP Inc	DOO	38.6	90.84	3,509	0.15%	0.57%	20.20%	0.0009%	0.0306%
Great-West Lifeco Inc	GWO	930.9	38.13	35,494	1.53%	5.14%	4.00%	0.0787%	0.0612%
Enbridge Inc	ENB	2026.3	54.76	110,959	4.78%	6.28%	7.15%	0.3005%	0.3421%
IGM Financial Inc	IGM	239.7	45.03	10,796	0.47%	5.00%	16.30%	0.0233%	0.0759%
Magna International Inc	MG	297.9	94.17	28,051	1.21%	2.45%	19.76%	0.0297%	0.2390%
Paramount Resources Ltd	POU	140.9	28.12	Excl.	Excl.	2.56%	n/a		
Shaw Communications Inc	SJR/B	476.8	38.01	18,122	0.78%	3.12%	2.00%	0.0244%	0.0156%
Martinrea International Inc	MRE	80.4	9.89	Excl.	Excl.	2.02%	n/a		
SNC-Lavalin Group Inc	SNC	175.6	28.54	Excl.	Excl.	0.28%	n/a		
Boardwalk Real Estate Investment Trust	BEI-U	46.5	56.45	Excl.	Excl.	1.91%	n/a		
Teck Resources Ltd	TECK/B	527.1	45.64	24,059	1.04%	1.10%	-11.33%	0.0114%	-0.1175%
Thomson Reuters Corp	TRI	486.2	128.16	62,310	2.69%	1.77%	12.10%	0.0475%	0.3251%
Whitecap Resources Inc	WCP	626.2	9.67	Excl.	Excl.	2.79%	n/a		

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Kinross Gold Corp	K	1244.3	6.32	Excl.	Excl.	2.45%	n/a		
RioCan Real Estate Investment Trust	REI-U	314.0	25.12	Excl.	Excl.	4.06%	n/a		
MAG Silver Corp	MAG	97.8	21.52	Excl.	Excl.	n/a	n/a		
TransAlta Corp	TA	271.2	12.87	Excl.	Excl.	1.55%	n/a		
Cargojet Inc	CJT	17.3	183.21	Excl.	Excl.	0.57%	n/a		
Gibson Energy Inc	GEI	146.6	24.74	Excl.	Excl.	5.98%	n/a		
CT Real Estate Investment Trust	CRT-U	105.7	16.94	1,791	0.08%	4.95%	17.65%	0.0038%	0.0136%
Vermilion Energy Inc	VET	162.3	23.7	Excl.	Excl.	n/a	n/a		
CI Financial Corp	CIX	197.4	20.75	4,097	0.18%	3.47%	12.40%	0.0061%	0.0219%
Osisko Mining Inc	OSK	348.8	3.93	Excl.	Excl.	n/a	n/a		
Yamana Gold Inc	YRI	959.8	6.23	5,980	0.26%	2.48%	2.11%	0.0064%	0.0054%
Dream Industrial Real Estate Investment Trust	DIR-U	227.9	16.84	3,839	0.17%	4.16%	16.25%	0.0069%	0.0269%
Wheaton Precious Metals Corp	WPM	450.9	55.54	25,041	1.08%	1.37%	5.00%	0.0147%	0.0540%
SilverCrest Metals Inc	SIL	145.6	11.03	Excl.	Excl.	n/a	n/a		
WSP Global Inc	WSP	117.9	155.51	Excl.	Excl.	0.96%	n/a		
Alimentation Couche-Tard Inc	ATD	1052.2	49.75	52,346	2.26%	0.88%	6.98%	0.0200%	0.1575%
Canopy Growth Corp	WEED	394.2	9.04	Excl.	Excl.	n/a	0.21%		
Quebecor Inc	QBR/B	162.3	27.72	4,498	0.19%	4.33%	3.82%	0.0084%	0.0074%
Intertape Polymer Group Inc	ITP	59.3	23.96	Excl.	Excl.	3.63%	n/a		
Power Corp of Canada	POW	621.6	39.09	24,298	1.05%	4.58%	4.00%	0.0480%	0.0419%
Alamos Gold Inc	AGI	391.9	9.34	3,660	0.16%	1.37%	12.43%	0.0022%	0.0196%
Open Text Corp	OTEX	271.2	55.16	Excl.	Excl.	2.03%	n/a		
MTY Food Group Inc	MTY	24.5	51.13	Excl.	Excl.	1.64%	n/a		
goeasy Ltd	GSY	16.1	150.19	Excl.	Excl.	2.42%	n/a		
Canadian National Railway Co	CNR	701.4	157.24	110,294	4.76%	1.86%	12.07%	0.0886%	0.5740%
IAMGOLD Corp	IMG	477.0	3.72	Excl.	Excl.	n/a	3.00%		
K92 Mining Inc	KNT	222.5	7.71	Excl.	Excl.	n/a	n/a		
Aurora Cannabis Inc	ACB	214.8	4.82	Excl.	Excl.	n/a	n/a		
ARC Resources Ltd	ARX	692.1	15.67	Excl.	Excl.	2.55%	n/a		
Enerplus Corp	ERF	243.3	16.2	Excl.	Excl.	1.03%	n/a		
Average for Companies Paying Dividends with Long-Term Growth Estimates					**100.00%**			**3.16%**	**7.96%**

Notes:
[1] Equals sum of Column [11]
[2] Equals [1] x (1 + 0.5 x [3])
[3] Equals sum of Column [12]
[4] Equals [2] + [3]
[5] Source: Bloomberg Finance L.P., as of February 28, 2022
[6] Source: Bloomberg Finance L.P., as of February 28, 2022
[7] Equals Column [5] x Column [6]. Excludes non-dividend paying companies and companies with no long-term growth estimates.
[8] Equals weight in index based on market capitalization. Excludes non-dividend paying companies and companies with no long-term growth estimates.
[9] Source: Bloomberg Finance L.P., as of February 28, 2022
[10] Source: Bloomberg Finance L.P., as of February 28, 2022
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]
[13] Source: April 2021 Consensus Forecast Average 2022-2024 Forecasts 10-Year bond yield plus 30-day average spread ending February 28, 2022 between 10- and 30-year government bonds
[14] Equals Column [4] - Column [13]

U.S. Market DCF Calculation as of February 28, 2022

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.91%**	**2.02%**	**11.42%**	**13.44%**	**3.18%**	**10.26%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
LyondellBasell Industries NV	LYB	328.0	97.23	31,892	0.11%	4.65%	8.00%	0.0052%	0.0090%
Signature Bank/New York NY	SBNY	62.6	344.89	21,579	0.08%	0.65%	12.25%	0.0005%	0.0093%
American Express Co	AXP	759.4	194.54	147,725	0.52%	0.88%	28.39%	0.0046%	0.1473%
Verizon Communications Inc	VZ	4197.8	53.67	225,297	0.79%	4.77%	2.90%	0.0377%	0.0229%
Broadcom Inc	AVGO	409.6	587.44	240,623	0.84%	2.79%	14.17%	0.0236%	0.1197%
Boeing Co/The	BA	583.0	205.34	Excl.	Excl.	n/a	80.64%		
Caterpillar Inc	CAT	535.9	187.58	100,522	0.35%	2.37%	11.73%	0.0084%	0.0414%
JPMorgan Chase & Co	JPM	2952.8	141.80	418,708	1.47%	2.82%	3.23%	0.0415%	0.0475%
Chevron Corp	CVX	1947.6	144.00	280,448	0.98%	3.94%	28.85%	0.0388%	0.2841%
Coca-Cola Co/The	KO	4335.5	62.24	269,840	0.95%	2.83%	9.69%	0.0268%	0.0918%
AbbVie Inc	ABBV	1768.8	147.77	261,369	0.92%	3.82%	-0.71%	0.0350%	-0.0065%
Walt Disney Co/The	DIS	1820.6	148.46	Excl.	Excl.	n/a	30.44%		
FleetCor Technologies Inc	FLT	81.2	234.20	Excl.	Excl.	n/a	16.01%		
Extra Space Storage Inc	EXR	134.2	188.15	25,241	0.09%	3.19%	11.62%	0.0028%	0.0103%
Exxon Mobil Corp	XOM	4233.6	78.42	331,998	1.17%	4.49%	26.88%	0.0523%	0.3134%
Phillips 66	PSX	438.5	84.24	36,936	0.13%	4.37%	7.28%	0.0057%	0.0094%
General Electric Co	GE	1099.3	95.51	104,996	0.37%	0.34%	8.50%	0.0012%	0.0313%
HP Inc	HPQ	1053.4	34.36	36,194	0.13%	2.91%	2.34%	0.0037%	0.0030%
Home Depot Inc/The	HD	1044.2	315.83	329,802	1.16%	2.41%	7.32%	0.0279%	0.0848%
Monolithic Power Systems Inc	MPWR	46.5	458.70	21,334	0.07%	0.65%	24.50%	0.0005%	0.0184%
International Business Machines Corp	IBM	899.3	122.51	110,174	0.39%	5.35%	13.42%	0.0207%	0.0519%
Johnson & Johnson	JNJ	2629.3	164.57	432,699	1.52%	2.58%	7.33%	0.0391%	0.1114%
McDonald's Corp	MCD	743.6	244.77	182,007	0.64%	2.26%	8.81%	0.0144%	0.0563%
Merck & Co Inc	MRK	2527.7	76.58	193,574	0.68%	3.60%	9.63%	0.0245%	0.0654%
3M Co	MMM	571.1	148.65	84,894	0.30%	4.01%	7.67%	0.0120%	0.0229%
American Water Works Co Inc	AWK	181.7	151.09	27,457	0.10%	1.60%	7.69%	0.0015%	0.0074%
Bank of America Corp	BAC	8069.8	44.20	356,685	1.25%	1.90%	3.50%	0.0238%	0.0438%
Pfizer Inc	PFE	5623.3	46.94	263,960	0.93%	3.41%	3.41%	0.0316%	0.0316%
Procter & Gamble Co/The	PG	2397.1	155.89	373,679	1.31%	2.23%	5.99%	0.0293%	0.0786%
AT&T Inc	T	7142.9	23.69	169,215	0.59%	8.78%	3.86%	0.0522%	0.0229%
Travelers Cos Inc/The	TRV	241.5	171.83	41,497	0.15%	2.05%	3.97%	0.0030%	0.0058%
Raytheon Technologies Corp	RTX	1492.3	102.70	153,262	0.54%	1.99%	13.46%	0.0107%	0.0725%
Analog Devices Inc	ADI	523.3	160.29	83,882	0.29%	1.90%	11.18%	0.0056%	0.0329%
Walmart Inc	WMT	2773.9	135.16	374,917	1.32%	1.66%	9.85%	0.0218%	0.1297%
Cisco Systems Inc/Delaware	CSCO	4154.2	55.77	231,678	0.81%	2.73%	5.20%	0.0222%	0.0423%
Intel Corp	INTC	4072.0	47.70	194,234	0.68%	3.06%	6.10%	0.0209%	0.0416%
General Motors Co	GM	1453.0	46.72	Excl.	Excl.	n/a	9.96%		
Microsoft Corp	MSFT	7496.9	298.79	2,239,989	7.87%	0.83%	12.78%	0.0653%	1.0052%
Dollar General Corp	DG	231.7	198.34	45,957	0.16%	0.85%	9.82%	0.0014%	0.0159%
Cigna Corp	CI	321.0	237.78	76,316	0.27%	1.88%	9.19%	0.0050%	0.0246%
Kinder Morgan Inc	KMI	2267.5	17.40	39,454	0.14%	6.21%	5.15%	0.0086%	0.0071%
Citigroup Inc	C	1980.9	59.23	117,328	0.41%	3.44%	9.23%	0.0142%	0.0380%
American International Group Inc	AIG	814.8	61.24	49,896	0.18%	2.09%	21.00%	0.0037%	0.0368%
Altria Group Inc	MO	1817.3	51.29	93,207	0.33%	7.02%	3.60%	0.0230%	0.0118%
HCA Healthcare Inc	HCA	303.6	250.31	75,994	0.27%	0.89%	12.65%	0.0024%	0.0338%
Under Armour Inc	UAA	188.7	17.89	Excl.	Excl.	n/a	25.00%		
International Paper Co	IP	376.4	43.53	16,383	0.06%	4.25%	16.90%	0.0024%	0.0097%
Hewlett Packard Enterprise Co	HPE	1300.3	15.92	20,700	0.07%	3.02%	4.28%	0.0022%	0.0031%
Abbott Laboratories	ABT	1763.5	120.62	212,711	0.75%	1.56%	11.67%	0.0116%	0.0871%
Aflac Inc	AFL	649.9	61.09	Excl.	Excl.	2.62%	n/a		
Air Products and Chemicals Inc	APD	221.7	236.30	52,392	0.18%	2.74%	13.78%	0.0050%	0.0253%

U.S. Market DCF Calculation as of February 28, 2022

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.91%**	**2.02%**	**11.42%**	**13.44%**	**3.18%**	**10.26%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Royal Caribbean Cruises Ltd	RCL	254.8	80.72	Excl.	Excl.	n/a	-188.41%		
Hess Corp	HES	309.7	101.06	31,301	0.11%	0.99%	47.10%	0.0011%	0.0518%
Archer-Daniels-Midland Co	ADM	562.2	78.45	44,102	0.15%	2.04%	1.24%	0.0032%	0.0019%
Automatic Data Processing Inc	ADP	420.0	204.44	85,874	0.30%	2.03%	13.45%	0.0061%	0.0406%
Verisk Analytics Inc	VRSK	161.3	177.34	Excl.	Excl.	0.70%	n/a		
AutoZone Inc	AZO	20.6	1863.39	Excl.	Excl.	n/a	10.57%		
Avery Dennison Corp	AVY	82.5	176.20	14,530	0.05%	1.54%	7.60%	0.0008%	0.0039%
Enphase Energy Inc	ENPH	133.9	166.70	Excl.	Excl.	n/a	36.20%		
MSCI Inc	MSCI	81.3	501.69	40,771	0.14%	0.83%	13.30%	0.0012%	0.0190%
Ball Corp	BLL	321.5	89.74	28,851	0.10%	0.89%	7.70%	0.0009%	0.0078%
Ceridian HCM Holding Inc	CDAY	152.1	72.91	Excl.	Excl.	n/a	58.30%		
Carrier Global Corp	CARR	855.5	44.88	38,395	0.13%	1.34%	8.95%	0.0018%	0.0121%
Bank of New York Mellon Corp/The	BK	804.5	53.15	42,759	0.15%	2.56%	9.50%	0.0038%	0.0143%
Otis Worldwide Corp	OTIS	425.0	78.33	33,287	0.12%	1.23%	9.63%	0.0014%	0.0113%
Baxter International Inc	BAX	502.3	84.97	42,680	0.15%	1.32%	13.05%	0.0020%	0.0196%
Becton Dickinson and Co	BDX	284.8	271.28	77,253	0.27%	1.28%	10.45%	0.0035%	0.0283%
Berkshire Hathaway Inc	BRK/B	1291.2	321.45	Excl.	Excl.	n/a	2.30%		
Best Buy Co Inc	BBY	240.6	96.64	23,248	0.08%	2.90%	7.07%	0.0024%	0.0058%
Boston Scientific Corp	BSX	1426.7	44.17	Excl.	Excl.	n/a	18.63%		
Bristol-Myers Squibb Co	BMY	2179.7	68.67	149,681	0.53%	3.15%	6.98%	0.0165%	0.0367%
Fortune Brands Home & Security Inc	FBHS	134.2	86.90	11,660	0.04%	1.29%	8.96%	0.0005%	0.0037%
Brown-Forman Corp	BF/B	309.7	65.23	20,205	0.07%	1.16%	7.68%	0.0008%	0.0054%
Coterra Energy Inc	CTRA	813.6	23.33	18,981	0.07%	9.60%	16.78%	0.0064%	0.0112%
Campbell Soup Co	CPB	301.7	44.97	13,569	0.05%	3.29%	2.31%	0.0016%	0.0011%
Hilton Worldwide Holdings Inc	HLT	279.1	148.86	Excl.	Excl.	n/a	37.88%		
Carnival Corp	CCL	986.4	20.33	Excl.	Excl.	n/a	n/a		
Qorvo Inc	QRVO	108.4	136.78	Excl.	Excl.	n/a	11.82%		
Lumen Technologies Inc	LUMN	1023.4	10.36	10,602	0.04%	9.65%	-10.47%	0.0036%	-0.0039%
UDR Inc	UDR	318.3	54.87	17,463	0.06%	2.64%	5.32%	0.0016%	0.0033%
Clorox Co/The	CLX	123.1	145.79	17,941	0.06%	3.18%	-0.45%	0.0020%	-0.0003%
Paycom Software Inc	PAYC	60.2	339.21	Excl.	Excl.	n/a	25.40%		
CMS Energy Corp	CMS	289.8	64.01	18,548	0.07%	2.87%	7.03%	0.0019%	0.0046%
Newell Brands Inc	NWL	425.5	23.75	10,106	0.04%	3.87%	7.00%	0.0014%	0.0025%
Colgate-Palmolive Co	CL	840.5	76.95	64,675	0.23%	2.34%	8.73%	0.0053%	0.0198%
EPAM Systems Inc	EPAM	56.9	207.75	Excl.	Excl.	n/a	25.70%		
Comerica Inc	CMA	131.1	95.49	12,517	0.04%	2.85%	11.22%	0.0013%	0.0049%
IPG Photonics Corp	IPGP	52.9	130.35	Excl.	Excl.	n/a	12.40%		
Conagra Brands Inc	CAG	479.7	34.97	16,775	0.06%	3.57%	6.45%	0.0021%	0.0038%
Consolidated Edison Inc	ED	354.1	85.77	30,370	0.11%	3.68%	3.85%	0.0039%	0.0041%
Corning Inc	GLW	845.8	40.40	34,172	0.12%	2.67%	11.45%	0.0032%	0.0137%
Cummins Inc	CMI	142.4	204.12	29,072	0.10%	2.84%	8.54%	0.0029%	0.0087%
Caesars Entertainment Inc	CZR	214.1	84.19	Excl.	Excl.	n/a	-39.81%		
Danaher Corp	DHR	715.4	274.41	196,300	0.69%	0.36%	21.85%	0.0025%	0.1506%
Target Corp	TGT	479.1	199.77	95,715	0.34%	1.80%	20.57%	0.0061%	0.0691%
Deere & Co	DE	306.8	360.02	110,448	0.39%	1.17%	14.68%	0.0045%	0.0569%
Dominion Energy Inc	D	810.5	79.53	64,456	0.23%	3.36%	6.87%	0.0076%	0.0155%
Dover Corp	DOV	144.1	156.86	22,596	0.08%	1.28%	14.60%	0.0010%	0.0116%
Alliant Energy Corp	LNT	250.5	58.40	14,628	0.05%	2.93%	5.97%	0.0015%	0.0031%
Duke Energy Corp	DUK	769.0	100.41	77,215	0.27%	3.92%	5.17%	0.0106%	0.0140%
Regency Centers Corp	REG	171.4	65.89	11,292	0.04%	3.79%	13.86%	0.0015%	0.0055%
Eaton Corp PLC	ETN	398.8	154.29	61,531	0.22%	2.10%	12.23%	0.0045%	0.0264%

U.S. Market DCF Calculation as of February 28, 2022

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.91%**	**2.02%**	**11.42%**	**13.44%**	**3.18%**	**10.26%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Ecolab Inc	ECL	286.8	176.26	50,543	0.18%	1.16%	14.50%	0.0021%	0.0257%
PerkinElmer Inc	PKI	126.2	179.61	22,667	0.08%	0.16%	1.60%	0.0001%	0.0013%
Emerson Electric Co	EMR	594.0	92.92	55,194	0.19%	2.22%	11.17%	0.0043%	0.0216%
EOG Resources Inc	EOG	585.4	114.92	67,276	0.24%	2.61%	9.74%	0.0062%	0.0230%
Aon PLC	AON	213.9	292.14	62,502	0.22%	0.70%	12.00%	0.0015%	0.0263%
Entergy Corp	ETR	203.0	105.21	21,361	0.08%	3.84%	4.85%	0.0029%	0.0036%
Equifax Inc	EFX	122.1	218.34	26,656	0.09%	0.71%	13.45%	0.0007%	0.0126%
IQVIA Holdings Inc	IQV	190.9	230.12	Excl.	Excl.	n/a	17.56%		
Gartner Inc	IT	82.3	280.42	Excl.	Excl.	n/a	13.50%		
FedEx Corp	FDX	265.0	222.27	58,895	0.21%	1.35%	12.20%	0.0028%	0.0252%
FMC Corp	FMC	125.7	117.25	14,738	0.05%	1.81%	9.23%	0.0009%	0.0048%
Brown & Brown Inc	BRO	282.2	67.61	19,081	0.07%	0.61%	8.00%	0.0004%	0.0054%
Ford Motor Co	F	3933.4	17.56	69,070	0.24%	2.28%	-6.94%	0.0055%	-0.0168%
NextEra Energy Inc	NEE	1962.7	78.27	153,624	0.54%	2.17%	9.45%	0.0117%	0.0510%
Franklin Resources Inc	BEN	502.1	29.73	Excl.	Excl.	3.90%	n/a		
Garmin Ltd	GRMN	192.8	110.44	21,291	0.07%	2.64%	11.10%	0.0020%	0.0083%
Freeport-McMoRan Inc	FCX	1454.8	46.95	68,302	0.24%	0.64%	-14.26%	0.0015%	-0.0342%
Dexcom Inc	DXCM	97.1	413.91	Excl.	Excl.	n/a	15.45%		
General Dynamics Corp	GD	277.7	234.45	65,106	0.23%	2.03%	10.29%	0.0046%	0.0235%
General Mills Inc	GIS	603.2	67.43	40,674	0.14%	3.03%	6.50%	0.0043%	0.0093%
Genuine Parts Co	GPC	142.0	122.16	17,342	0.06%	2.93%	16.20%	0.0018%	0.0099%
Atmos Energy Corp	ATO	135.4	109.81	14,872	0.05%	2.48%	7.39%	0.0013%	0.0039%
WW Grainger Inc	GWW	51.1	477.06	24,382	0.09%	1.36%	12.27%	0.0012%	0.0105%
Halliburton Co	HAL	898.6	33.53	30,129	0.11%	1.43%	44.87%	0.0015%	0.0475%
L3Harris Technologies Inc	LHX	193.1	252.31	48,712	0.17%	1.78%	4.39%	0.0030%	0.0075%
Healthpeak Properties Inc	PEAK	539.3	31.06	16,751	0.06%	3.86%	12.16%	0.0023%	0.0071%
Catalent Inc	CTLT	179.1	102.04	Excl.	Excl.	n/a	17.25%		
Fortive Corp	FTV	359.1	64.75	23,252	0.08%	0.43%	10.63%	0.0004%	0.0087%
Hershey Co/The	HSY	145.6	202.26	29,455	0.10%	1.78%	7.75%	0.0018%	0.0080%
Synchrony Financial	SYF	521.3	42.78	22,300	0.08%	2.06%	36.95%	0.0016%	0.0289%
Hormel Foods Corp	HRL	542.6	47.64	25,848	0.09%	2.18%	6.71%	0.0020%	0.0061%
Arthur J Gallagher & Co	AJG	208.5	158.19	32,989	0.12%	1.29%	14.81%	0.0015%	0.0172%
Mondelez International Inc	MDLZ	1388.3	65.48	90,908	0.32%	2.14%	7.58%	0.0068%	0.0242%
CenterPoint Energy Inc	CNP	628.9	27.35	17,199	0.06%	2.49%	3.53%	0.0015%	0.0021%
Humana Inc	HUM	126.6	434.32	55,000	0.19%	0.73%	12.70%	0.0014%	0.0245%
Willis Towers Watson PLC	WTW	117.7	222.30	26,175	0.09%	1.48%	16.00%	0.0014%	0.0147%
Illinois Tool Works Inc	ITW	312.9	216.34	67,699	0.24%	2.26%	11.60%	0.0054%	0.0276%
CDW Corp/DE	CDW	134.9	172.46	23,272	0.08%	1.16%	13.10%	0.0009%	0.0107%
Trane Technologies PLC	TT	233.5	153.93	35,949	0.13%	1.74%	11.84%	0.0022%	0.0149%
Interpublic Group of Cos Inc/The	IPG	394.0	36.80	14,498	0.05%	3.15%	3.07%	0.0016%	0.0016%
International Flavors & Fragrances Inc	IFF	254.7	133.00	33,873	0.12%	2.38%	6.62%	0.0028%	0.0079%
Jacobs Engineering Group Inc	J	129.2	123.00	15,894	0.06%	0.75%	13.56%	0.0004%	0.0076%
Generac Holdings Inc	GNRC	63.8	315.47	Excl.	Excl.	n/a	11.10%		
NXP Semiconductors NV	NXPI	262.5	190.12	49,914	0.18%	1.78%	18.60%	0.0031%	0.0326%
Kellogg Co	K	341.7	63.94	21,847	0.08%	3.63%	4.05%	0.0028%	0.0031%
Broadridge Financial Solutions Inc	BR	116.8	146.21	17,073	0.06%	1.75%	12.20%	0.0010%	0.0073%
Kimberly-Clark Corp	KMB	337.0	130.15	43,860	0.15%	3.57%	-1.35%	0.0055%	-0.0021%
Kimco Realty Corp	KIM	616.7	23.53	14,510	0.05%	3.23%	8.91%	0.0016%	0.0045%
Oracle Corp	ORCL	2670.4	75.97	202,874	0.71%	1.68%	7.57%	0.0120%	0.0539%
Kroger Co/The	KR	735.3	46.80	34,410	0.12%	1.79%	8.26%	0.0022%	0.0100%
Lennar Corp	LEN	261.4	89.88	23,492	0.08%	1.67%	4.55%	0.0014%	0.0037%

U.S. Market DCF Calculation as of February 28, 2022

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.91%**	**2.02%**	**11.42%**	**13.44%**	**3.18%**	**10.26%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalizatio n ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Eli Lilly & Co	LLY	952.3	249.95	238,039	0.84%	1.57%	14.41%	0.0131%	0.1205%
Bath & Body Works Inc	BBWI	257.7	53.37	13,755	0.05%	1.50%	9.26%	0.0007%	0.0045%
Charter Communications Inc	CHTR	172.7	601.78	Excl.	Excl.	n/a	25.32%		
Lincoln National Corp	LNC	172.5	67.42	11,627	0.04%	2.67%	20.79%	0.0011%	0.0085%
Loews Corp	L	248.2	61.34	Excl.	Excl.	0.41%	n/a		
Lowe's Cos Inc	LOW	670.0	221.06	148,110	0.52%	1.45%	18.83%	0.0075%	0.0979%
IDEX Corp	IEX	76.1	191.90	14,607	0.05%	1.13%	13.00%	0.0006%	0.0067%
Marsh & McLennan Cos Inc	MMC	502.8	155.41	78,135	0.27%	1.38%	7.81%	0.0038%	0.0214%
Masco Corp	MAS	239.9	56.04	13,445	0.05%	2.00%	12.42%	0.0009%	0.0059%
S&P Global Inc	SPGI	354.4	375.70	133,133	0.47%	0.90%	8.60%	0.0042%	0.0402%
Medtronic PLC	MDT	1342.6	104.99	140,956	0.49%	2.40%	7.50%	0.0119%	0.0371%
Viatris Inc	VTRS	1209.4	11.01	Excl.	Excl.	4.36%	n/a		
CVS Health Corp	CVS	1312.5	103.65	136,042	0.48%	2.12%	7.20%	0.0101%	0.0344%
DuPont de Nemours Inc	DD	512.9	77.37	39,684	0.14%	1.71%	10.43%	0.0024%	0.0145%
Micron Technology Inc	MU	1119.8	88.86	99,503	0.35%	0.45%	17.17%	0.0016%	0.0600%
Motorola Solutions Inc	MSI	168.2	220.43	37,078	0.13%	1.43%	11.20%	0.0019%	0.0146%
Cboe Global Markets Inc	CBOE	106.6	117.29	Excl.	Excl.	1.64%	n/a		
Laboratory Corp of America Holdings	LH	93.4	271.26	Excl.	Excl.	n/a	-6.59%		
Newmont Corp	NEM	792.5	66.20	52,464	0.18%	3.32%	-3.00%	0.0061%	-0.0055%
NIKE Inc	NKE	1276.3	136.55	174,277	0.61%	0.89%	14.74%	0.0055%	0.0902%
NiSource Inc	NI	405.4	28.93	11,728	0.04%	3.25%	6.69%	0.0013%	0.0028%
Norfolk Southern Corp	NSC	239.8	256.52	61,508	0.22%	1.93%	11.31%	0.0042%	0.0244%
Principal Financial Group Inc	PFG	261.2	70.64	18,453	0.06%	3.62%	8.30%	0.0023%	0.0054%
Eversource Energy	ES	344.4	81.80	28,175	0.10%	3.12%	7.66%	0.0031%	0.0076%
Northrop Grumman Corp	NOC	156.1	442.14	69,019	0.24%	1.42%	0.30%	0.0034%	0.0007%
Wells Fargo & Co	WFC	3814.6	53.37	203,583	0.71%	1.87%	8.01%	0.0134%	0.0572%
Nucor Corp	NUE	269.1	131.62	Excl.	Excl.	1.52%	n/a		
PVH Corp	PVH	70.0	97.89	6,850	0.02%	0.15%	56.81%	0.0000%	0.0137%
Occidental Petroleum Corp	OXY	934.1	43.73	Excl.	Excl.	1.19%	n/a		
Omnicom Group Inc	OMC	209.0	83.89	17,532	0.06%	3.34%	8.77%	0.0021%	0.0054%
ONEOK Inc	OKE	445.9	65.30	Excl.	Excl.	5.73%	n/a		
Raymond James Financial Inc	RJF	207.6	109.65	22,764	0.08%	1.24%	10.90%	0.0010%	0.0087%
Parker-Hannifin Corp	PH	128.5	296.39	38,080	0.13%	1.39%	13.15%	0.0019%	0.0176%
Rollins Inc	ROL	492.1	32.63	16,057	0.06%	1.23%	11.10%	0.0007%	0.0063%
PPL Corp	PPL	735.4	26.17	19,244	0.07%	3.06%	5.20%	0.0021%	0.0035%
ConocoPhillips	COP	1299.5	94.86	Excl.	Excl.	1.94%	n/a		
PulteGroup Inc	PHM	248.7	49.66	12,348	0.04%	1.21%	24.62%	0.0005%	0.0107%
Pinnacle West Capital Corp	PNW	112.9	70.83	7,999	0.03%	4.80%	-3.77%	0.0013%	-0.0011%
PNC Financial Services Group Inc/The	PNC	418.5	199.25	83,377	0.29%	2.51%	21.40%	0.0073%	0.0627%
PPG Industries Inc	PPG	236.0	133.45	31,494	0.11%	1.77%	12.66%	0.0020%	0.0140%
Progressive Corp/The	PGR	584.8	105.93	61,953	0.22%	0.38%	32.79%	0.0008%	0.0713%
Public Service Enterprise Group Inc	PEG	502.1	64.83	32,550	0.11%	3.33%	3.28%	0.0038%	0.0038%
Robert Half International Inc	RHI	110.7	120.29	13,314	0.05%	1.43%	-6.90%	0.0007%	-0.0032%
Edison International	EIX	380.7	63.42	24,144	0.08%	4.42%	3.05%	0.0037%	0.0026%
Schlumberger NV	SLB	1413.0	39.24	55,447	0.19%	1.27%	43.92%	0.0025%	0.0855%
Charles Schwab Corp/The	SCHW	1814.6	84.46	153,263	0.54%	0.95%	21.75%	0.0051%	0.1171%
Sherwin-Williams Co/The	SHW	260.4	263.13	68,512	0.24%	0.91%	10.11%	0.0022%	0.0243%
West Pharmaceutical Services Inc	WST	74.3	387.08	28,753	0.10%	0.19%	8.57%	0.0002%	0.0086%
J M Smucker Co/The	SJM	108.4	134.75	14,602	0.05%	2.94%	1.49%	0.0015%	0.0008%
Snap-on Inc	SNA	53.4	210.18	11,232	0.04%	2.70%	6.89%	0.0011%	0.0027%
AMETEK Inc	AME	231.7	129.79	30,072	0.11%	0.68%	11.67%	0.0007%	0.0123%

U.S. Market DCF Calculation as of February 28, 2022

	[1]	[2]	[3]	[4]	[13]	[14]
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S&P 500 INDEX	**1.91%**	**2.02%**	**11.42%**	**13.44%**	**3.18%**	**10.26%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalizatio n ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Southern Co/The	SO	1059.8	64.77	68,644	0.24%	4.08%	5.03%	0.0098%	0.0121%
Truist Financial Corp	TFC	1328.1	62.22	82,636	0.29%	3.09%	9.07%	0.0090%	0.0263%
Southwest Airlines Co	LUV	592.3	43.80	Excl.	Excl.	n/a	29.70%		
W R Berkley Corp	WRB	176.8	90.30	15,964	0.06%	0.58%	13.67%	0.0003%	0.0077%
Stanley Black & Decker Inc	SWK	163.4	162.70	26,577	0.09%	1.94%	8.53%	0.0018%	0.0080%
Public Storage	PSA	175.5	355.02	62,293	0.22%	2.25%	12.89%	0.0049%	0.0282%
Arista Networks Inc	ANET	307.8	122.73	Excl.	Excl.	n/a	17.19%		
Sysco Corp	SYY	507.4	87.10	44,199	0.16%	2.16%	13.95%	0.0033%	0.0217%
Corteva Inc	CTVA	726.5	52.03	37,801	0.13%	1.08%	11.10%	0.0014%	0.0147%
Texas Instruments Inc	TXN	923.5	169.99	156,994	0.55%	2.71%	8.30%	0.0149%	0.0458%
Textron Inc	TXT	216.7	73.13	15,846	0.06%	0.11%	13.88%	0.0001%	0.0077%
Thermo Fisher Scientific Inc	TMO	391.2	544.00	212,808	0.75%	0.22%	10.28%	0.0016%	0.0768%
TJX Cos Inc/The	TJX	1192.9	66.10	78,849	0.28%	1.79%	69.15%	0.0049%	0.1915%
Globe Life Inc	GL	99.3	100.96	Excl.	Excl.	0.78%	n/a		
Johnson Controls International plc	JCI	702.6	64.96	45,643	0.16%	2.09%	14.30%	0.0034%	0.0229%
Ulta Beauty Inc	ULTA	54.1	374.50	Excl.	Excl.	n/a	45.46%		
Union Pacific Corp	UNP	636.9	245.95	156,645	0.55%	1.92%	9.33%	0.0106%	0.0513%
Keysight Technologies Inc	KEYS	180.8	157.37	Excl.	Excl.	n/a	10.31%		
UnitedHealth Group Inc	UNH	940.9	475.87	447,746	1.57%	1.22%	12.19%	0.0192%	0.1917%
Marathon Oil Corp	MRO	730.8	22.56	16,486	0.06%	1.24%	-1.68%	0.0007%	-0.0010%
Bio-Rad Laboratories Inc	BIO	24.9	625.96	Excl.	Excl.	n/a	13.90%		
Ventas Inc	VTR	399.5	54.00	21,573	0.08%	3.33%	13.82%	0.0025%	0.0105%
VF Corp	VFC	388.9	58.02	22,564	0.08%	3.45%	29.56%	0.0027%	0.0234%
Vornado Realty Trust	VNO	191.7	43.28	8,298	0.03%	4.90%	-15.89%	0.0014%	-0.0046%
Vulcan Materials Co	VMC	132.8	181.45	24,095	0.08%	0.88%	24.14%	0.0007%	0.0204%
Weyerhaeuser Co	WY	746.3	38.88	Excl.	Excl.	1.85%	n/a		
Whirlpool Corp	WHR	58.6	201.27	11,797	0.04%	3.48%	6.16%	0.0014%	0.0026%
Williams Cos Inc/The	WMB	1215.6	31.28	38,024	0.13%	5.43%	6.00%	0.0073%	0.0080%
Constellation Energy Corp	CEG	326.0	45.98	Excl.	Excl.	1.23%	n/a		
WEC Energy Group Inc	WEC	315.4	90.88	28,667	0.10%	3.20%	6.62%	0.0032%	0.0067%
Adobe Inc	ADBE	471.7	467.68	Excl.	Excl.	n/a	16.45%		
AES Corp/The	AES	667.4	21.23	14,169	0.05%	2.98%	8.00%	0.0015%	0.0040%
Amgen Inc	AMGN	557.0	226.48	126,156	0.44%	3.43%	7.40%	0.0152%	0.0328%
Apple Inc	AAPL	16319.4	165.12	2,694,666	9.46%	0.53%	9.40%	0.0504%	0.8895%
Autodesk Inc	ADSK	220.0	220.23	Excl.	Excl.	n/a	16.90%		
Cintas Corp	CTAS	103.7	375.32	38,933	0.14%	1.01%	6.00%	0.0014%	0.0082%
Comcast Corp	CMCSA	4523.8	46.76	211,532	0.74%	2.31%	10.68%	0.0172%	0.0793%
Molson Coors Beverage Co	TAP	200.6	52.18	10,467	0.04%	2.91%	5.98%	0.0011%	0.0022%
KLA Corp	KLAC	150.7	348.50	52,524	0.18%	1.21%	14.54%	0.0022%	0.0268%
Marriott International Inc/MD	MAR	326.3	170.14	Excl.	Excl.	n/a	40.03%		
McCormick & Co Inc/MD	MKC	249.7	95.17	23,768	0.08%	1.56%	5.05%	0.0013%	0.0042%
PACCAR Inc	PCAR	347.6	91.81	31,911	0.11%	1.48%	10.90%	0.0017%	0.0122%
Costco Wholesale Corp	COST	443.4	519.25	230,252	0.81%	0.61%	10.71%	0.0049%	0.0866%
First Republic Bank/CA	FRC	179.1	173.26	31,024	0.11%	0.51%	12.39%	0.0006%	0.0135%
Stryker Corp	SYK	377.5	263.35	99,426	0.35%	1.06%	12.07%	0.0037%	0.0421%
Tyson Foods Inc	TSN	292.5	92.66	27,099	0.10%	1.99%	0.78%	0.0019%	0.0007%
Lamb Weston Holdings Inc	LW	145.2	66.43	9,646	0.03%	1.48%	13.26%	0.0005%	0.0045%
Applied Materials Inc	AMAT	883.4	134.20	118,552	0.42%	0.72%	12.18%	0.0030%	0.0507%
American Airlines Group Inc	AAL	649.2	17.25	Excl.	Excl.	n/a	n/a		
Cardinal Health Inc	CAH	277.1	54.01	14,964	0.05%	3.63%	4.34%	0.0019%	0.0023%
Cerner Corp	CERN	293.3	93.25	27,354	0.10%	1.16%	11.00%	0.0011%	0.0106%

U.S. Market DCF Calculation as of February 28, 2022

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
S&P 500 INDEX	**1.91%**	**2.02%**	**11.42%**	**13.44%**	**3.18%**	**10.26%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price ($)	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Cincinnati Financial Corp	CINF	160.4	122.79	Excl.	Excl.	2.25%	n/a		
Paramount Global	PARA	607.9	30.61	18,607	0.07%	3.14%	1.85%	0.0020%	0.0012%
DR Horton Inc	DHI	354.4	85.40	30,262	0.11%	1.05%	18.07%	0.0011%	0.0192%
Electronic Arts Inc	EA	281.2	130.09	36,584	0.13%	0.52%	9.30%	0.0007%	0.0119%
Expeditors International of Washington Inc	EXPD	169.4	103.36	17,510	0.06%	1.12%	-7.65%	0.0007%	-0.0047%
Fastenal Co	FAST	575.6	51.46	29,618	0.10%	2.41%	9.30%	0.0025%	0.0097%
M&T Bank Corp	MTB	129.0	182.23	23,514	0.08%	2.63%	7.54%	0.0022%	0.0062%
Xcel Energy Inc	XEL	544.2	67.33	36,642	0.13%	2.90%	6.90%	0.0037%	0.0089%
Fiserv Inc	FISV	652.2	97.67	Excl.	Excl.	n/a	16.40%		
Fifth Third Bancorp	FITB	683.7	47.84	32,707	0.11%	2.51%	2.20%	0.0029%	0.0025%
Gilead Sciences Inc	GILD	1253.9	60.40	75,735	0.27%	4.83%	8.67%	0.0129%	0.0230%
Hasbro Inc	HAS	139.0	97.05	13,486	0.05%	2.89%	5.60%	0.0014%	0.0027%
Huntington Bancshares Inc/OH	HBAN	1438.1	15.52	22,319	0.08%	3.99%	17.65%	0.0031%	0.0138%
Welltower Inc	WELL	447.3	83.29	37,254	0.13%	2.93%	19.74%	0.0038%	0.0258%
Biogen Inc	BIIB	147.0	211.01	Excl.	Excl.	n/a	-5.95%		
Northern Trust Corp	NTRS	207.9	113.90	23,680	0.08%	2.46%	13.60%	0.0020%	0.0113%
Packaging Corp of America	PKG	93.5	147.19	13,767	0.05%	2.72%	3.00%	0.0013%	0.0015%
Paychex Inc	PAYX	360.8	119.06	42,952	0.15%	2.22%	9.00%	0.0033%	0.0136%
People's United Financial Inc	PBCT	427.9	21.08	Excl.	Excl.	3.46%	n/a		
QUALCOMM Inc	QCOM	1127.0	171.99	193,833	0.68%	1.58%	15.57%	0.0108%	0.1060%
Roper Technologies Inc	ROP	105.6	448.22	47,333	0.17%	0.55%	11.93%	0.0009%	0.0198%
Ross Stores Inc	ROST	353.3	91.39	32,291	0.11%	1.25%	53.80%	0.0014%	0.0610%
IDEXX Laboratories Inc	IDXX	84.2	532.35	Excl.	Excl.	n/a	10.92%		
Starbucks Corp	SBUX	1150.3	91.79	105,586	0.37%	2.14%	12.48%	0.0079%	0.0463%
KeyCorp	KEY	927.8	25.07	23,259	0.08%	3.11%	19.12%	0.0025%	0.0156%
Fox Corp	FOXA	315.8	41.83	13,210	0.05%	1.15%	8.39%	0.0005%	0.0039%
Fox Corp	FOX	247.1	38.26	9,454	0.03%	1.25%	8.39%	0.0004%	0.0028%
State Street Corp	STT	366.1	85.33	31,236	0.11%	2.67%	10.20%	0.0029%	0.0112%
Norwegian Cruise Line Holdings Ltd	NCLH	416.9	19.49	Excl.	Excl.	n/a	153.32%		
US Bancorp	USB	1483.9	56.54	83,900	0.29%	3.25%	9.31%	0.0096%	0.0274%
A O Smith Corp	AOS	131.4	68.58	9,012	0.03%	1.63%	10.00%	0.0005%	0.0032%
NortonLifeLock Inc	NLOK	582.2	28.98	16,872	0.06%	1.73%	9.50%	0.0010%	0.0056%
T Rowe Price Group Inc	TROW	228.1	144.56	32,973	0.12%	3.32%	3.32%	0.0038%	0.0038%
Waste Management Inc	WM	414.6	144.40	59,866	0.21%	1.59%	11.37%	0.0033%	0.0239%
Constellation Brands Inc	STZ	164.3	215.62	35,435	0.12%	1.41%	8.05%	0.0018%	0.0100%
DENTSPLY SIRONA Inc	XRAY	218.6	54.14	11,835	0.04%	0.92%	10.25%	0.0004%	0.0043%
Zions Bancorp NA	ZION	151.6	70.89	10,745	0.04%	2.14%	8.93%	0.0008%	0.0034%
Alaska Air Group Inc	ALK	125.9	56.14	Excl.	Excl.	n/a	n/a		
Invesco Ltd	IVZ	460.8	21.24	9,786	0.03%	3.20%	0.20%	0.0011%	0.0001%
Linde PLC	LIN	508.3	293.24	149,063	0.52%	1.60%	9.73%	0.0084%	0.0509%
Intuit Inc	INTU	283.2	474.37	134,326	0.47%	0.57%	17.43%	0.0027%	0.0822%
Morgan Stanley	MS	1781.3	90.74	161,635	0.57%	3.09%	3.33%	0.0175%	0.0189%
Microchip Technology Inc	MCHP	556.0	70.33	39,103	0.14%	1.44%	17.71%	0.0020%	0.0243%
Chubb Ltd	CB	426.2	203.64	86,797	0.30%	1.57%	12.87%	0.0048%	0.0392%
Hologic Inc	HOLX	250.0	71.17	Excl.	Excl.	n/a	-18.45%		
Citizens Financial Group Inc	CFG	422.1	52.42	22,129	0.08%	2.98%	0.99%	0.0023%	0.0008%
O'Reilly Automotive Inc	ORLY	66.6	649.24	Excl.	Excl.	n/a	15.72%		
Allstate Corp/The	ALL	278.3	122.36	34,058	0.12%	2.78%	3.63%	0.0033%	0.0043%
Equity Residential	EQR	375.9	85.30	32,066	0.11%	2.83%	10.96%	0.0032%	0.0123%
BorgWarner Inc	BWA	240.0	41.01	9,841	0.03%	1.66%	29.15%	0.0006%	0.0101%
Organon & Co	OGN	253.6	37.33	9,465	0.03%	3.00%	-2.99%	0.0010%	-0.0010%

U.S. Market DCF Calculation as of February 28, 2022

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.91%**	**2.02%**	**11.42%**	**13.44%**	**3.18%**	**10.26%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Host Hotels & Resorts Inc	HST	714.2	18.27	Excl.	Excl.	0.16%	n/a		
Incyte Corp	INCY	221.3	68.30	Excl.	Excl.	n/a	36.00%		
Simon Property Group Inc	SPG	342.8	137.56	47,162	0.17%	4.80%	8.67%	0.0079%	0.0144%
Eastman Chemical Co	EMN	129.0	118.47	15,279	0.05%	2.57%	13.76%	0.0014%	0.0074%
Twitter Inc	TWTR	800.6	35.55	Excl.	Excl.	n/a	39.00%		
AvalonBay Communities Inc	AVB	139.8	238.59	33,343	0.12%	2.67%	8.02%	0.0031%	0.0094%
Prudential Financial Inc	PRU	376.3	111.66	42,018	0.15%	4.30%	2.40%	0.0063%	0.0035%
United Parcel Service Inc	UPS	732.6	210.42	154,144	0.54%	2.89%	8.90%	0.0156%	0.0482%
Walgreens Boots Alliance Inc	WBA	863.3	46.09	39,788	0.14%	4.14%	0.74%	0.0058%	0.0010%
STERIS PLC	STE	100.1	240.00	24,030	0.08%	0.72%	10.80%	0.0006%	0.0091%
McKesson Corp	MCK	149.8	274.96	41,188	0.14%	0.68%	11.66%	0.0010%	0.0169%
Lockheed Martin Corp	LMT	272.3	433.80	118,135	0.41%	2.58%	4.12%	0.0107%	0.0171%
AmerisourceBergen Corp	ABC	209.1	142.53	29,808	0.10%	1.29%	8.25%	0.0014%	0.0086%
Capital One Financial Corp	COF	413.7	153.27	63,402	0.22%	1.57%	41.05%	0.0035%	0.0914%
Waters Corp	WAT	60.5	316.73	Excl.	Excl.	n/a	10.35%		
Nordson Corp	NDSN	57.9	226.49	13,123	0.05%	0.90%	11.93%	0.0004%	0.0055%
Dollar Tree Inc	DLTR	225.0	142.08	Excl.	Excl.	n/a	11.55%		
Darden Restaurants Inc	DRI	127.7	145.22	18,548	0.07%	3.03%	12.85%	0.0020%	0.0084%
Match Group Inc	MTCH	285.1	111.49	Excl.	Excl.	n/a	48.47%		
Domino's Pizza Inc	DPZ	36.4	432.21	Excl.	Excl.	0.87%	n/a		
NVR Inc	NVR	3.4	4958.44	Excl.	Excl.	n/a	26.00%		
NetApp Inc	NTAP	222.3	78.38	17,422	0.06%	2.55%	11.16%	0.0016%	0.0068%
Citrix Systems Inc	CTXS	125.5	102.50	12,869	0.05%	1.44%	10.20%	0.0007%	0.0046%
DXC Technology Co	DXC	244.5	34.03	Excl.	Excl.	n/a	27.18%		
Old Dominion Freight Line Inc	ODFL	114.9	314.03	36,071	0.13%	0.38%	17.72%	0.0005%	0.0224%
DaVita Inc	DVA	96.3	112.77	Excl.	Excl.	n/a	10.56%		
Hartford Financial Services Group Inc/The	HIG	331.6	69.48	23,043	0.08%	2.22%	7.00%	0.0018%	0.0057%
Iron Mountain Inc	IRM	289.8	49.18	14,254	0.05%	5.03%	4.00%	0.0025%	0.0020%
Estee Lauder Cos Inc/The	EL	232.4	296.33	68,874	0.24%	0.81%	12.21%	0.0020%	0.0295%
Cadence Design Systems Inc	CDNS	277.3	151.43	Excl.	Excl.	n/a	13.72%		
Tyler Technologies Inc	TYL	41.3	428.26	Excl.	Excl.	n/a	16.27%		
Universal Health Services Inc	UHS	67.6	143.93	9,723	0.03%	0.56%	9.42%	0.0002%	0.0032%
Skyworks Solutions Inc	SWKS	164.0	138.17	22,661	0.08%	1.62%	9.94%	0.0013%	0.0079%
Quest Diagnostics Inc	DGX	119.5	131.27	15,681	0.06%	2.01%	-6.42%	0.0011%	-0.0035%
Activision Blizzard Inc	ATVI	779.2	81.50	63,508	0.22%	0.58%	10.80%	0.0013%	0.0241%
Rockwell Automation Inc	ROK	116.2	266.58	30,976	0.11%	1.68%	10.46%	0.0018%	0.0114%
Kraft Heinz Co/The	KHC	1223.7	39.22	47,995	0.17%	4.08%	4.60%	0.0069%	0.0078%
American Tower Corp	AMT	455.9	226.87	103,427	0.36%	2.45%	13.04%	0.0089%	0.0474%
Regeneron Pharmaceuticals Inc	REGN	106.7	618.36	Excl.	Excl.	n/a	-3.27%		
Amazon.com Inc	AMZN	508.8	3071.26	Excl.	Excl.	n/a	18.87%		
Jack Henry & Associates Inc	JKHY	72.8	176.80	12,875	0.05%	1.11%	15.05%	0.0005%	0.0068%
Ralph Lauren Corp	RL	46.3	132.04	6,112	0.02%	2.08%	90.72%	0.0004%	0.0195%
Boston Properties Inc	BXP	156.7	122.31	19,163	0.07%	3.20%	-8.21%	0.0022%	-0.0055%
Amphenol Corp	APH	598.9	76.01	45,525	0.16%	1.05%	10.14%	0.0017%	0.0162%
Howmet Aerospace Inc	HWM	418.9	35.92	15,047	0.05%	0.22%	33.00%	0.0001%	0.0174%
Pioneer Natural Resources Co	PXD	242.9	239.60	58,195	0.20%	6.31%	13.23%	0.0129%	0.0270%
Valero Energy Corp	VLO	409.3	83.51	Excl.	Excl.	4.69%	n/a		
Synopsys Inc	SNPS	153.1	312.39	Excl.	Excl.	n/a	16.36%		
Etsy Inc	ETSY	127.0	154.89	Excl.	Excl.	n/a	23.77%		
CH Robinson Worldwide Inc	CHRW	128.8	96.68	12,452	0.04%	2.28%	12.65%	0.0010%	0.0055%
Accenture PLC	ACN	658.3	316.02	208,046	0.73%	1.23%	11.00%	0.0090%	0.0804%

U.S. Market DCF Calculation as of February 28, 2022

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TransDigm Group Inc	TDG	55.5	666.59	Excl.	Excl.	n/a	23.15%		
Yum! Brands Inc	YUM	289.0	122.58	35,423	0.12%	1.86%	11.59%	0.0023%	0.0144%
Prologis Inc	PLD	739.7	145.85	107,892	0.38%	2.17%	8.27%	0.0082%	0.0313%
FirstEnergy Corp	FE	570.3	41.85	23,869	0.08%	3.73%	4.63%	0.0031%	0.0039%
VeriSign Inc	VRSN	110.2	213.72	Excl.	Excl.	n/a	8.80%		
Quanta Services Inc	PWR	142.7	108.94	15,545	0.05%	0.26%	14.50%	0.0001%	0.0079%
Henry Schein Inc	HSIC	137.2	86.38	Excl.	Excl.	n/a	14.95%		
Ameren Corp	AEE	255.4	85.95	21,952	0.08%	2.75%	7.70%	0.0021%	0.0059%
ANSYS Inc	ANSS	87.2	324.19	Excl.	Excl.	n/a	11.65%		
FactSet Research Systems Inc	FDS	37.8	406.09	15,349	0.05%	0.81%	9.00%	0.0004%	0.0049%
NVIDIA Corp	NVDA	2500.0	243.85	609,625	2.14%	0.07%	25.13%	0.0014%	0.5380%
Sealed Air Corp	SEE	148.2	67.13	9,946	0.03%	1.19%	8.79%	0.0004%	0.0031%
Cognizant Technology Solutions Corp	CTSH	524.5	86.13	45,178	0.16%	1.25%	12.40%	0.0020%	0.0197%
SVB Financial Group	SIVB	58.7	606.00	Excl.	Excl.	n/a	7.00%		
Intuitive Surgical Inc	ISRG	357.7	290.33	Excl.	Excl.	n/a	3.25%		
Take-Two Interactive Software Inc	TTWO	115.4	162.00	Excl.	Excl.	n/a	9.90%		
Republic Services Inc	RSG	316.4	120.28	38,060	0.13%	1.53%	8.76%	0.0020%	0.0117%
eBay Inc	EBAY	587.5	54.59	32,073	0.11%	1.61%	8.92%	0.0018%	0.0100%
Goldman Sachs Group Inc/The	GS	337.9	341.29	115,330	0.40%	2.34%	6.80%	0.0095%	0.0275%
SBA Communications Corp	SBAC	108.8	303.39	33,003	0.12%	0.94%	23.30%	0.0011%	0.0270%
Sempra Energy	SRE	315.1	144.22	45,440	0.16%	3.18%	5.85%	0.0051%	0.0093%
Moody's Corp	MCO	185.2	322.03	59,640	0.21%	0.87%	10.00%	0.0018%	0.0209%
Booking Holdings Inc	BKNG	40.9	2172.25	Excl.	Excl.	n/a	28.35%		
F5 Inc	FFIV	60.7	200.85	Excl.	Excl.	n/a	13.60%		
Akamai Technologies Inc	AKAM	160.3	108.26	Excl.	Excl.	n/a	16.30%		
Charles River Laboratories International Inc	CRL	50.5	291.16	Excl.	Excl.	n/a	15.15%		
MarketAxess Holdings Inc	MKTX	37.8	381.43	14,431	0.05%	0.73%	10.80%	0.0004%	0.0055%
Devon Energy Corp	DVN	664.2	59.55	39,553	0.14%	6.72%	16.68%	0.0093%	0.0232%
Alphabet Inc	GOOGL	300.8	2701.14	Excl.	Excl.	n/a	20.34%		
Bio-Techne Corp	TECH	39.3	419.41	16,478	0.06%	0.31%	25.07%	0.0002%	0.0145%
Teleflex Inc	TFX	46.8	336.31	15,754	0.06%	0.40%	11.70%	0.0002%	0.0065%
Netflix Inc	NFLX	444.0	394.52	Excl.	Excl.	n/a	27.97%		
Allegion plc	ALLE	88.2	114.52	10,104	0.04%	1.43%	7.09%	0.0005%	0.0025%
Agilent Technologies Inc	A	302.0	130.36	39,369	0.14%	0.64%	10.65%	0.0009%	0.0147%
Anthem Inc	ANTM	241.3	451.85	109,033	0.38%	1.13%	10.09%	0.0043%	0.0386%
Trimble Inc	TRMB	251.2	69.75	Excl.	Excl.	n/a	10.00%		
CME Group Inc	CME	359.4	236.53	85,008	0.30%	1.69%	7.85%	0.0050%	0.0234%
Juniper Networks Inc	JNPR	322.8	33.79	10,906	0.04%	2.49%	8.85%	0.0010%	0.0034%
BlackRock Inc	BLK	152.0	743.89	113,103	0.40%	2.62%	10.00%	0.0104%	0.0397%
DTE Energy Co	DTE	193.8	121.59	23,558	0.08%	2.91%	5.87%	0.0024%	0.0049%
Nasdaq Inc	NDAQ	164.4	171.15	28,139	0.10%	1.26%	10.64%	0.0012%	0.0105%
Celanese Corp	CE	108.0	139.28	15,046	0.05%	1.95%	8.26%	0.0010%	0.0044%
Philip Morris International Inc	PM	1549.8	101.07	156,641	0.55%	4.95%	7.86%	0.0272%	0.0432%
salesforce.com Inc	CRM	985.0	210.53	Excl.	Excl.	n/a	17.28%		
Ingersoll Rand Inc	IR	408.0	50.52	20,611	0.07%	0.16%	14.85%	0.0001%	0.0107%
Huntington Ingalls Industries Inc	HII	40.0	204.40	8,174	0.03%	2.31%	25.20%	0.0007%	0.0072%
MetLife Inc	MET	825.1	67.55	55,734	0.20%	2.84%	1.41%	0.0056%	0.0027%
Under Armour Inc	UA	253.2	15.63	Excl.	Excl.	n/a	n/a		
Tapestry Inc	TPR	264.0	40.90	10,797	0.04%	2.44%	13.53%	0.0009%	0.0051%
CSX Corp	CSX	2193.4	33.91	74,378	0.26%	1.18%	12.45%	0.0031%	0.0325%
Edwards Lifesciences Corp	EW	623.2	112.37	Excl.	Excl.	n/a	14.33%		

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S&P 500 INDEX	**1.91%**	**2.02%**	**11.42%**	**13.44%**	**3.18%**	**10.26%**

Company	Ticker	[5] Shares Outstanding (million)	[6] Price ($)	[7] Market Capitalizatio n ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Ameriprise Financial Inc	AMP	110.8	299.79	33,202	0.12%	1.51%	14.50%	0.0018%	0.0169%
Zebra Technologies Corp	ZBRA	53.1	413.34	Excl.	Excl.	n/a	10.80%		
Zimmer Biomet Holdings Inc	ZBH	209.2	123.39	25,810	0.09%	0.78%	8.63%	0.0007%	0.0078%
CBRE Group Inc	CBRE	334.7	96.85	Excl.	Excl.	n/a	19.40%		
Mastercard Inc	MA	969.7	360.82	349,898	1.23%	0.54%	22.26%	0.0067%	0.2735%
CarMax Inc	KMX	161.7	109.33	Excl.	Excl.	n/a	17.07%		
Intercontinental Exchange Inc	ICE	561.9	128.12	71,984	0.25%	1.19%	9.55%	0.0030%	0.0241%
Fidelity National Information Services Inc	FIS	609.6	95.23	58,051	0.20%	1.97%	11.81%	0.0040%	0.0241%
Chipotle Mexican Grill Inc	CMG	28.0	1523.35	Excl.	Excl.	n/a	29.20%		
Wynn Resorts Ltd	WYNN	115.9	86.52	Excl.	Excl.	n/a	n/a		
Live Nation Entertainment Inc	LYV	224.6	120.82	Excl.	Excl.	n/a	n/a		
Assurant Inc	AIZ	55.2	169.71	9,362	0.03%	1.60%	17.67%	0.0005%	0.0058%
NRG Energy Inc	NRG	242.2	37.84	9,163	0.03%	3.70%	29.36%	0.0012%	0.0094%
Regions Financial Corp	RF	937.1	24.19	22,670	0.08%	2.81%	-1.12%	0.0022%	-0.0009%
Monster Beverage Corp	MNST	529.4	84.40	Excl.	Excl.	n/a	10.20%		
Mosaic Co/The	MOS	368.3	52.43	19,310	0.07%	0.86%	-5.67%	0.0006%	-0.0038%
Baker Hughes Co	BKR	953.3	29.38	28,009	0.10%	2.45%	63.81%	0.0024%	0.0628%
Expedia Group Inc	EXPE	150.2	196.11	Excl.	Excl.	n/a	32.25%		
Evergy Inc	EVRG	227.0	62.41	14,167	0.05%	3.67%	6.21%	0.0018%	0.0031%
Discovery Inc	DISCA	169.6	28.05	Excl.	Excl.	n/a	-2.75%		
CF Industries Holdings Inc	CF	207.3	81.19	16,831	0.06%	1.48%	8.87%	0.0009%	0.0052%
Leidos Holdings Inc	LDOS	140.5	101.84	14,309	0.05%	1.41%	7.17%	0.0007%	0.0036%
APA Corp	APA	346.8	35.63	12,356	0.04%	1.40%	14.62%	0.0006%	0.0063%
Alphabet Inc	GOOG	315.6	2697.82	Excl.	Excl.	n/a	20.34%		
TE Connectivity Ltd	TEL	325.6	142.43	46,372	0.16%	1.57%	9.02%	0.0026%	0.0147%
Cooper Cos Inc/The	COO	49.3	409.02	20,163	0.07%	0.01%	11.90%	0.0000%	0.0084%
Discover Financial Services	DFS	284.9	123.44	35,169	0.12%	1.62%	25.35%	0.0020%	0.0313%
Visa Inc	V	1658.4	216.12	358,419	1.26%	0.69%	18.44%	0.0087%	0.2321%
Mid-America Apartment Communities Inc	MAA	115.3	204.61	Excl.	Excl.	2.13%	n/a		
Xylem Inc/NY	XYL	179.9	88.95	16,002	0.06%	1.35%	15.75%	0.0008%	0.0089%
Marathon Petroleum Corp	MPC	565.2	77.87	44,013	0.15%	2.98%	10.93%	0.0046%	0.0169%
Tractor Supply Co	TSCO	112.8	203.79	22,982	0.08%	1.81%	9.10%	0.0015%	0.0073%
Advanced Micro Devices Inc	AMD	1627.4	123.34	Excl.	Excl.	n/a	32.95%		
ResMed Inc	RMD	146.2	246.75	36,083	0.13%	0.68%	15.97%	0.0009%	0.0202%
Mettler-Toledo International Inc	MTD	22.8	1408.74	Excl.	Excl.	n/a	17.37%		
Copart Inc	CPRT	237.2	122.88	Excl.	Excl.	n/a	n/a		
Albemarle Corp	ALB	117.0	195.89	22,926	0.08%	0.81%	24.28%	0.0006%	0.0195%
Fortinet Inc	FTNT	160.8	344.52	Excl.	Excl.	n/a	17.16%		
Moderna Inc	MRNA	402.9	153.60	Excl.	Excl.	n/a	-165.06%		
Essex Property Trust Inc	ESS	65.3	317.17	20,705	0.07%	2.77%	7.22%	0.0020%	0.0052%
Realty Income Corp	O	591.3	66.09	39,080	0.14%	4.48%	7.57%	0.0061%	0.0104%
Westrock Co	WRK	263.2	45.27	11,916	0.04%	2.21%	14.21%	0.0009%	0.0059%
IHS Markit Ltd	INFO	#N/A N/A	#N/A N/A	Excl.	Excl.	n/a	11.20%		
Westinghouse Air Brake Technologies Corp	WAB	185.3	92.82	17,199	0.06%	0.65%	10.27%	0.0004%	0.0062%
Pool Corp	POOL	40.2	458.58	Excl.	Excl.	0.70%	n/a		
Western Digital Corp	WDC	312.9	50.94	Excl.	Excl.	n/a	13.62%		
PepsiCo Inc	PEP	1383.5	163.74	226,526	0.80%	2.63%	7.35%	0.0209%	0.0585%
Diamondback Energy Inc	FANG	177.4	138.10	24,501	0.09%	1.74%	23.11%	0.0015%	0.0199%
ServiceNow Inc	NOW	200.0	579.92	Excl.	Excl.	n/a	36.00%		
Church & Dwight Co Inc	CHD	242.7	97.85	23,747	0.08%	1.07%	6.83%	0.0009%	0.0057%
Duke Realty Corp	DRE	382.8	53.00	20,287	0.07%	2.11%	7.56%	0.0015%	0.0054%

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Federal Realty Investment Trust	FRT	78.6	117.58	9,244	0.03%	3.64%	13.11%	0.0012%	0.0043%
MGM Resorts International	MGM	439.2	44.29	19,451	0.07%	0.02%	0.85%	0.0000%	0.0006%
American Electric Power Co Inc	AEP	504.2	90.65	45,707	0.16%	3.44%	6.24%	0.0055%	0.0100%
SolarEdge Technologies Inc	SEDG	52.8	319.42	Excl.	Excl.	n/a	23.27%		
PTC Inc	PTC	117.0	111.28	Excl.	Excl.	n/a	12.14%		
JB Hunt Transport Services Inc	JBHT	104.9	202.93	21,277	0.07%	0.79%	21.50%	0.0006%	0.0161%
Lam Research Corp	LRCX	139.5	561.35	78,308	0.27%	1.07%	13.53%	0.0029%	0.0372%
Mohawk Industries Inc	MHK	65.1	140.78	Excl.	Excl.	n/a	13.59%		
Pentair PLC	PNR	165.1	57.91	9,561	0.03%	1.45%	9.60%	0.0005%	0.0032%
Vertex Pharmaceuticals Inc	VRTX	254.6	230.02	Excl.	Excl.	n/a	28.98%		
Amcor PLC	AMCR	1513.7	11.63	17,605	0.06%	4.13%	7.80%	0.0026%	0.0048%
Meta Platforms Inc	FB	2309.1	211.03	Excl.	Excl.	n/a	19.42%		
T-Mobile US Inc	TMUS	1249.3	123.21	Excl.	Excl.	n/a	20.33%		
United Rentals Inc	URI	72.4	321.62	Excl.	Excl.	n/a	14.01%		
ABIOMED Inc	ABMD	45.5	310.74	Excl.	Excl.	n/a	n/a		
Honeywell International Inc	HON	685.8	189.75	130,134	0.46%	2.07%	10.35%	0.0094%	0.0473%
Alexandria Real Estate Equities Inc	ARE	159.9	189.40	30,293	0.11%	2.43%	-2.12%	0.0026%	-0.0023%
Delta Air Lines Inc	DAL	639.9	39.92	Excl.	Excl.	n/a	86.00%		
Seagate Technology Holdings PLC	STX	218.9	103.16	22,582	0.08%	2.71%	8.18%	0.0022%	0.0065%
United Airlines Holdings Inc	UAL	323.6	44.40	Excl.	Excl.	n/a	n/a		
News Corp	NWS	198.5	22.43	4,452	0.02%	0.89%	14.30%	0.0001%	0.0022%
Centene Corp	CNC	582.9	82.62	Excl.	Excl.	n/a	10.65%		
Martin Marietta Materials Inc	MLM	62.4	379.40	23,673	0.08%	0.64%	13.23%	0.0005%	0.0110%
Teradyne Inc	TER	162.4	117.92	19,152	0.07%	0.37%	12.64%	0.0003%	0.0085%
PayPal Holdings Inc	PYPL	1165.0	111.93	Excl.	Excl.	n/a	19.93%		
Tesla Inc	TSLA	1033.5	870.43	Excl.	Excl.	n/a	36.20%		
DISH Network Corp	DISH	290.6	31.96	Excl.	Excl.	n/a	1.75%		
Dow Inc	DOW	735.7	58.96	43,380	0.15%	4.75%	27.00%	0.0072%	0.0411%
Penn National Gaming Inc	PENN	168.3	51.35	Excl.	Excl.	n/a	16.00%		
Everest Re Group Ltd	RE	39.3	298.22	11,712	0.04%	2.08%	41.40%	0.0009%	0.0170%
Teledyne Technologies Inc	TDY	47.2	429.38	Excl.	Excl.	n/a	9.22%		
News Corp	NWSA	390.9	22.32	8,724	0.03%	0.90%	14.30%	0.0003%	0.0044%
Exelon Corp	EXC	978.3	42.56	Excl.	Excl.	3.17%	n/a		
Global Payments Inc	GPN	282.0	133.38	37,609	0.13%	0.75%	17.43%	0.0010%	0.0230%
Crown Castle International Corp	CCI	432.2	166.59	72,003	0.25%	3.53%	10.10%	0.0089%	0.0255%
Aptiv PLC	APTV	270.5	129.44	Excl.	Excl.	n/a	22.27%		
Advance Auto Parts Inc	AAP	61.1	204.48	12,493	0.04%	2.93%	16.53%	0.0013%	0.0073%
Align Technology Inc	ALGN	78.8	511.46	Excl.	Excl.	n/a	15.28%		
Illumina Inc	ILMN	157.0	326.60	Excl.	Excl.	n/a	31.19%		
LKQ Corp	LKQ	285.0	46.95	13,381	0.05%	2.13%	3.30%	0.0010%	0.0016%
Nielsen Holdings PLC	NLSN	359.5	17.42	Excl.	Excl.	1.38%	n/a		
Zoetis Inc	ZTS	472.0	193.65	91,397	0.32%	0.67%	12.56%	0.0022%	0.0403%
Zimvie Inc	ZIMV	#N/A N/A	38.00	Excl.	Excl.	n/a	n/a		
Equinix Inc	EQIX	90.7	709.73	64,387	0.23%	1.75%	18.30%	0.0040%	0.0414%
Digital Realty Trust Inc	DLR	284.5	134.92	38,381	0.13%	3.44%	14.56%	0.0046%	0.0196%
Las Vegas Sands Corp	LVS	764.0	42.86	Excl.	Excl.	n/a	n/a		
Discovery Inc	DISCK	330.2	27.97	Excl.	Excl.	n/a	-2.75%		
					100.00%			**1.91%**	**11.42%**

Notes:

U.S. Market DCF Calculation as of February 28, 2022

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500 INDEX	**1.91%**	**2.02%**	**11.42%**	**13.44%**	**3.18%**	**10.26%**

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate

[1] Equals sum of Column [11]
[2] Equals [1] x (1 + 0.5 x [3])
[3] Equals sum of Column [12]
[4] Equals [2] + [3]
[5] Source: Bloomberg Finance L.P., as of February 28, 2022
[6] Source: Bloomberg Finance L.P., as of February 28, 2022
[7] Equals Column [5] x Column [6]. Excludes non-dividend paying companies and companies with no long-term growth estimates.
[8] Equals weight in index based on market capitalization. Excludes non-dividend paying companies and companies with no long-term growth estimates.
[9] Source: Bloomberg Finance L.P., as of February 28, 2022
[10] Source: Bloomberg Finance L.P., as of February 28, 2022
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]
[13] Source: April 2021 Consensus Forecast Average 2022-2024 Forecasts 10-Year bond yield plus 30-day average spread between 10- and 30-year government bonds ending February 28, 2022
[14] Equals [4] - [13]

Capital Asset Pricing Model - Average MRP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Canadian Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
Algonquin Power & Utilities Corp.	AQN	0.97	n/a	0.97	2.84%	7.86%	10.45%	0.50%	10.95%
AltaGas Ltd.	ALA	1.20	n/a	1.20	2.84%	7.86%	12.27%	0.50%	12.77%
Canadian Utilities Limited	CU	0.87	n/a	0.87	2.84%	7.86%	9.68%	0.50%	10.18%
Enbridge Inc	ENB	0.94	0.90	0.92	2.84%	7.86%	10.06%	0.50%	10.56%
Emera Inc.	EMA	0.69	0.75	0.72	2.84%	7.86%	8.52%	0.50%	9.02%
Hydro One Ltd.	H	0.67	n/a	0.67	2.84%	7.86%	8.12%	0.50%	8.62%
MEAN		0.89	0.83	0.89			9.85%		10.35%

US Electric Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
ALLETE, Inc.	ALE	0.90	0.90	0.90	3.18%	7.86%	10.27%	0.50%	10.77%
Alliant Energy Corporation	LNT	0.86	0.85	0.86	3.18%	7.86%	9.92%	0.50%	10.42%
Duke Energy Corporation	DUK	0.80	0.85	0.83	3.18%	7.86%	9.69%	0.50%	10.19%
Edison International	EIX	0.93	0.95	0.94	3.18%	7.86%	10.56%	0.50%	11.06%
Entergy Corporation	ETR	0.96	0.95	0.95	3.18%	7.86%	10.69%	0.50%	11.19%
Evergy Inc	EVRG	0.88	0.95	0.91	3.18%	7.86%	10.36%	0.50%	10.86%
IDACORP, Inc.	IDA	0.85	0.80	0.83	3.18%	7.86%	9.67%	0.50%	10.17%
NextEra Energy, Inc.	NEE	0.85	0.95	0.90	3.18%	7.86%	10.25%	0.50%	10.75%
OGE Energy Corporation	OGE	1.04	1.05	1.04	3.18%	7.86%	11.38%	0.50%	11.88%
Portland General Electric Company	POR	0.87	0.90	0.88	3.18%	7.86%	10.14%	0.50%	10.64%
MEAN		0.89	0.92	0.90			10.29%		10.79%

Capital Asset Pricing Model - Average MRP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
North American Electric Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
Algonquin Power and Utilities	AQN	0.97	n/a	0.97	2.84%	7.86%	10.45%	0.50%	10.95%
Canadian Utilities Limited	CU	0.87	n/a	0.87	2.84%	7.86%	9.68%	0.50%	10.18%
Emera Inc.	EMA	0.69	0.75	0.72	2.84%	7.86%	8.52%	0.50%	9.02%
Hydro One, Ltd.	H	0.67	n/a	0.67	2.84%	7.86%	8.12%	0.50%	8.62%
ALLETE, Inc.	ALE	0.90	0.90	0.90	3.18%	7.86%	10.27%	0.50%	10.77%
Alliant Energy Corporation	LNT	0.86	0.85	0.86	3.18%	7.86%	9.92%	0.50%	10.42%
Duke Energy Corporation	DUK	0.80	0.85	0.83	3.18%	7.86%	9.69%	0.50%	10.19%
Edison International	EIX	0.93	0.95	0.94	3.18%	7.86%	10.56%	0.50%	11.06%
Entergy Corporation	ETR	0.96	0.95	0.95	3.18%	7.86%	10.69%	0.50%	11.19%
Evergy Inc	EVRG	0.88	0.95	0.91	3.18%	7.86%	10.36%	0.50%	10.86%
IDACORP, Inc.	IDA	0.85	0.80	0.83	3.18%	7.86%	9.67%	0.50%	10.17%
NextEra Energy, Inc.	NEE	0.85	0.95	0.90	3.18%	7.86%	10.25%	0.50%	10.75%
OGE Energy Corporation	OGE	1.04	1.05	1.04	3.18%	7.86%	11.38%	0.50%	11.88%
Portland General Electric Company	POR	0.87	0.90	0.88	3.18%	7.86%	10.14%	0.50%	10.64%
MEAN		0.87	0.90	0.88			9.98%		10.48%

Notes:

[1] Source: Bloomberg Professional as of February 28, 2022; weekly changes in equity stock price against SPX index (U.S.) or SPTSX (Canada) Index for the past five years

[2] Source: Value Line as of February 28, 2022

[3] Equals mean of [1] and [2]

[4] Source: Equals average long-term Consensus Forecast of 10-year government bond yields for the period 2023-2025 as of October 11, 2021. (Pg. 3, 28) plus the average spread between 10- and 30-year bond for the month of February 2022.

[5] Source: Average of Bloomberg TSX total return less [4] as of February 28, 2022, the Bloomberg S&P 500 total return less [4] as of February 28,2022, the Duff and Phelps Canada historical risk premium of 5.54%, and the Duff and Phelps US historical risk premium of 7.25%.

[6] Equals [4] + ([3] x [5])

[7] Flotation cost adjustment for equity issuance costs, administrative costs, impact of underpricing, potential for dilution, and equity cushion for investors.

[8] Equals [6] + [7]

Capital Asset Pricing Model - Forward-Looking MRP

Canadian Proxy Group	Ticker	[1] Bloomberg	[2] Value Line	[3] Average Beta	[4] Risk Free Rate	[5] Market Risk Premium	[6] Basic CAPM Calculation	[7] Flotation Cost	[8] Total CAPM
Algonquin Power & Utilities Corp.	AQN	0.97	n/a	0.97	2.84%	9.33%	11.87%	0.50%	12.37%
AltaGas Ltd.	ALA	1.20	n/a	1.20	2.84%	9.33%	14.03%	0.50%	14.53%
Canadian Utilities Limited	CU	0.87	n/a	0.87	2.84%	9.33%	10.96%	0.50%	11.46%
Enbridge Inc	ENB	0.94	0.90	0.92	2.84%	9.33%	11.41%	0.50%	11.91%
Emera Inc.	EMA	0.69	0.75	0.72	2.84%	9.33%	9.58%	0.50%	10.08%
Hydro One Ltd.	H	0.67	n/a	0.67	2.84%	9.33%	9.11%	0.50%	9.61%
MEAN		0.89	0.83	0.89			11.16%		11.66%

US Electric Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
ALLETE, Inc.	ALE	0.90	0.90	0.90	3.18%	9.33%	11.60%	0.50%	12.10%
Alliant Energy Corporation	LNT	0.86	0.85	0.86	3.18%	9.33%	11.18%	0.50%	11.68%
Duke Energy Corporation	DUK	0.80	0.85	0.83	3.18%	9.33%	10.90%	0.50%	11.40%
Edison International	EIX	0.93	0.95	0.94	3.18%	9.33%	11.94%	0.50%	12.44%
Entergy Corporation	ETR	0.96	0.95	0.95	3.18%	9.33%	12.09%	0.50%	12.59%
Evergy Inc	EVRG	0.88	0.95	0.91	3.18%	9.33%	11.70%	0.50%	12.20%
IDACORP, Inc.	IDA	0.85	0.80	0.83	3.18%	9.33%	10.89%	0.50%	11.39%
NextEra Energy, Inc.	NEE	0.85	0.95	0.90	3.18%	9.33%	11.57%	0.50%	12.07%
OGE Energy Corporation	OGE	1.04	1.05	1.04	3.18%	9.33%	12.92%	0.50%	13.42%
Portland General Electric Company	POR	0.87	0.90	0.88	3.18%	9.33%	11.44%	0.50%	11.94%
MEAN		0.89	0.92	0.90			11.62%		12.12%

Capital Asset Pricing Model - Forward-Looking MRP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
North American Electric Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
Algonquin Power and Utilities	AQN	0.97	n/a	0.97	2.84%	9.33%	11.87%	0.50%	12.37%
Canadian Utilities Limited	CU	0.87	n/a	0.87	2.84%	9.33%	10.96%	0.50%	11.46%
Emera Inc.	EMA	0.69	0.75	0.72	2.84%	9.33%	9.58%	0.50%	10.08%
Hydro One, Ltd.	H	0.67	n/a	0.67	2.84%	9.33%	9.11%	0.50%	9.61%
ALLETE, Inc.	ALE	0.90	0.90	0.90	3.18%	9.33%	11.60%	0.50%	12.10%
Alliant Energy Corporation	LNT	0.86	0.85	0.86	3.18%	9.33%	11.18%	0.50%	11.68%
Duke Energy Corporation	DUK	0.80	0.85	0.83	3.18%	9.33%	10.90%	0.50%	11.40%
Edison International	EIX	0.93	0.95	0.94	3.18%	9.33%	11.94%	0.50%	12.44%
Entergy Corporation	ETR	0.96	0.95	0.95	3.18%	9.33%	12.09%	0.50%	12.59%
Evergy Inc	EVRG	0.88	0.95	0.91	3.18%	9.33%	11.70%	0.50%	12.20%
IDACORP, Inc.	IDA	0.85	0.80	0.83	3.18%	9.33%	10.89%	0.50%	11.39%
NextEra Energy, Inc.	NEE	0.85	0.95	0.90	3.18%	9.33%	11.57%	0.50%	12.07%
OGE Energy Corporation	OGE	1.04	1.05	1.04	3.18%	9.33%	12.92%	0.50%	13.42%
Portland General Electric Company	POR	0.87	0.90	0.88	3.18%	9.33%	11.44%	0.50%	11.94%
MEAN		0.87	0.90	0.88			11.27%		11.77%

Notes:

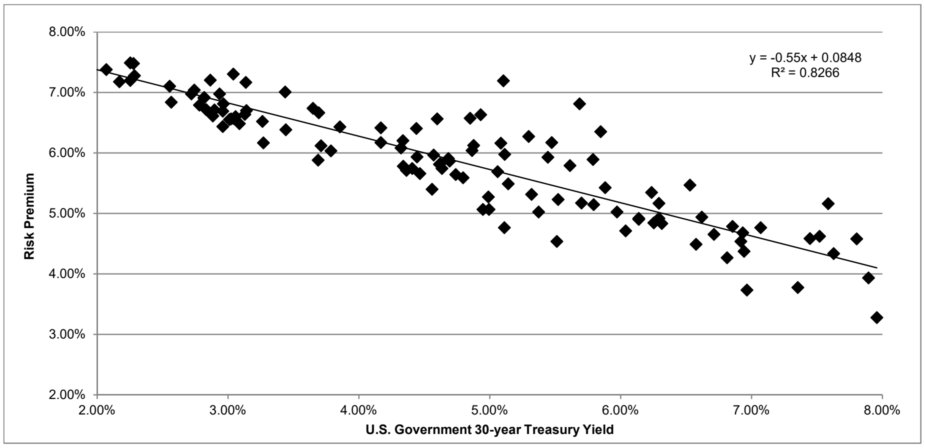
[1] Source: Bloomberg Professional as of February 28, 2022; weekly changes in equity stock price against SPX index (U.S.) or SPTSX (Canada) Index for the past five years
[2] Source: Value Line as of February 28, 2022
[3] Equals mean of [1] and [2]
[4] Source: Equals average long-term Consensus Forecast of 10-year government bond yields for the period 2023-2025 as of October 11, 2021. (Pg. 3, 28) plus the average spread between 10- and 30-year bond for the month of February 2022.
[5] Source: Average of Bloomberg TSX total return less [4] as of February 28, 2022 and Bloomberg S&P 500 total return less [4] as of February 28, 2022
[6] Equals [4] + ([3] x [5])
[7] Flotation cost adjustment for equity issuance costs, administrative costs, impact of underpricing, potential for dilution, and equity cushion for investors.
[8] Equals [6] + [7]

Risk Premium -- Electric Utilities

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	10.88%	5.70%	5.18%
2001.3	10.76%	5.52%	5.23%
2001.4	11.57%	5.30%	6.27%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.25%	5.08%	6.17%
2002.4	11.57%	4.93%	6.64%
2003.1	11.43%	4.85%	6.58%
2003.2	11.16%	4.60%	6.56%
2003.3	9.88%	5.11%	4.76%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	10.91%	4.86%	6.04%
2005.1	10.56%	4.69%	5.87%
2005.2	10.13%	4.47%	5.66%
2005.3	10.85%	4.44%	6.41%
2005.4	10.59%	4.68%	5.91%
2006.1	10.38%	4.63%	5.75%
2006.2	10.63%	5.14%	5.49%
2006.3	10.06%	4.99%	5.07%
2006.4	10.39%	4.74%	5.65%
2007.1	10.39%	4.80%	5.59%
2007.2	10.27%	4.99%	5.28%
2007.3	10.02%	4.95%	5.07%
2007.4	10.43%	4.61%	5.81%
2008.1	10.15%	4.41%	5.75%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.94%
2008.4	10.39%	3.65%	6.74%
2009.1	10.45%	3.44%	7.01%
2009.2	10.58%	4.17%	6.42%
2009.3	10.41%	4.32%	6.09%
2009.4	10.54%	4.34%	6.21%
2010.1	10.45%	4.62%	5.82%
2010.2	10.08%	4.36%	5.71%
2010.3	10.29%	3.86%	6.43%
2010.4	10.34%	4.17%	6.17%
2011.1	9.96%	4.56%	5.40%
2011.2	10.12%	4.34%	5.78%

Risk Premium -- Electric Utilities

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2011.3	10.36%	3.69%	6.67%
2011.4	10.34%	3.04%	7.31%
2012.1	10.30%	3.14%	7.17%
2012.2	9.92%	2.93%	6.98%
2012.3	9.78%	2.74%	7.04%
2012.4	10.07%	2.86%	7.21%
2013.1	9.77%	3.13%	6.64%
2013.2	9.84%	3.14%	6.70%
2013.3	9.83%	3.71%	6.12%
2013.4	9.82%	3.79%	6.04%
2014.1	9.57%	3.69%	5.88%
2014.2	9.83%	3.44%	6.39%
2014.3	9.79%	3.26%	6.52%
2014.4	9.78%	2.96%	6.81%
2015.1	9.66%	2.55%	7.11%
2015.2	9.50%	2.88%	6.61%
2015.3	9.40%	2.96%	6.44%
2015.4	9.65%	2.96%	6.69%
2016.1	9.70%	2.72%	6.98%
2016.2	9.41%	2.57%	6.84%
2016.3	9.76%	2.28%	7.48%
2016.4	9.55%	2.83%	6.72%
2017.1	9.61%	3.04%	6.57%
2017.2	9.61%	2.90%	6.71%
2017.3	9.73%	2.82%	6.91%
2017.4	9.74%	2.82%	6.92%
2018.1	9.59%	3.02%	6.57%
2018.2	9.57%	3.09%	6.49%
2018.3	9.66%	3.06%	6.60%
2018.4	9.44%	3.27%	6.17%
2019.1	9.57%	3.01%	6.56%
2019.2	9.58%	2.78%	6.79%
2019.3	9.57%	2.29%	7.28%
2019.4	9.74%	2.25%	7.49%
2020.1	9.45%	1.89%	7.56%
2020.2	9.52%	1.38%	8.14%
2020.3	9.34%	1.37%	7.98%
2020.4	9.32%	1.62%	7.70%
2021.1	9.45%	2.07%	7.38%
2021.2	9.46%	2.25%	7.20%
2021.3	9.37%	1.93%	7.44%
2021.4	9.36%	1.94%	7.41%
2022.1	9.35%	2.17%	7.18%
AVERAGE	10.54%	4.58%	5.96%
MEDIAN	10.40%	4.62%	6.04%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.90919026
R Square	0.82662694
Adjusted R Square	0.82517002
Standard Error	0.0042183
Observations	121

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010096032	0.010096032	567.3811303	4.20007E-47
Residual	119	0.002117497	1.77941E-05		
Total	120	0.012213529			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.08477338	0.001125074	75.34913869	2.847E-102	0.082545624	0.0870011	0.08254562	0.08700114
U.S. Govt. 30-year Treasury	-0.5500432	0.023091882	-23.81976344	4.20007E-47	-0.595767412	-0.504319	-0.5957674	-0.5043189

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	2.20%	7.27%	9.47%
Blue Chip Consensus Forecast (Q4 2022 - Q2 2023) [5]	2.74%	6.97%	9.71%
Blue Chip Consensus Forecast (2023-2027) [6]	3.40%	6.61%	10.01%
AVERAGE			9.73%

Notes:
[1] Source: Regulatory Research Associates, rate cases through February 28, 2022
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of February 28, 2022
[5] Source: Blue Chip Financial Forecasts, Vol. 41, No. 3, March 1, 2022 at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021 at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.084773 + (-0.550043 x Column [7])
[9] Equals Column [7] + Column [8]

2018-2020 % Regulated

Utility		**% Regulated Income**	**% Electric Revenues**	**% Electric Income**	**% Electric Assets**
ALLETE, Inc.	ALE	89%	98%	97%	98%
Alliant Energy Corporation	LNT	96%	86%	91%	86%
Duke Energy Corporation	DUK	99%	92%	91%	91%
Edison International	EIX	90%	100%	100%	100%
Entergy Corporation	ETR	100%	99%	99%	99%
Evergy Inc	EVRG	100%	100%	100%	100%
IDACORP, Inc.	IDA	100%	100%	100%	100%
NextEra Energy, Inc.	NEE	76%	100%	100%	100%
OGE Energy Corporation	OGE	100%	100%	100%	100%
Portland General Electric Company	POR	100%	100%	100%	100%
U.S. Proxy Group Average		**95%**	**97%**	**98%**	**97%**

Note: Percentage of operating income may exceed 100% due to losses at affiliates.

Credit Metrics Analysis

Company Name	Ticker	Rating	Debt to Capital Ratio	EBITDA Interest Coverage	FFO to Cash Interest Coverage	FFO / Debt (%)	Debt to EBITDA
			2021	2021	2021	2021	2021
Maritime Electric Company Ltd. (Estimated)		BBB+	64.9%	4.65	2.80	14.2%	4.25
U.S. Electric Proxy Group [1]							
ALLETE, Inc.	ALE	BBB	42.7%	5.27	6.10	16.4%	5.11
Alliant Energy Corporation	LNT	A-	58.1%	5.18	5.26	14.4%	5.63
Duke Energy Corporation	DUK	BBB+	59.1%	4.16	5.22	13.5%	5.98
Edison International	EIX	BBB	66.6%	5.10	6.16	15.7%	5.41
Entergy Corporation	ETR	BBB+	72.7%	3.92	5.18	11.8%	6.72
Evergy Inc	EVRG	A-	56.7%	5.51	6.43	16.8%	5.08
IDACORP, Inc.	IDA	BBB	45.5%	5.32	5.18	17.9%	4.21
NextEra Energy, Inc.	NEE	A-	42.9%	6.43	6.88	21.0%	4.09
OGE Energy Corporation	OGE	BBB+	56.1%	6.41	6.45	17.0%	4.93
Portland General Electric Company	POR	BBB+	58.8%	5.21	6.17	17.3%	4.74
U.S. Electric Proxy Group		BBB+	55.9%	5.25	5.90	16.2%	5.19
Canadian Proxy Group [1]							
Algonquin Power and Utilities	AQN	BBB	35.7%	4.84	4.68	14.3%	5.46
AltaGas Inc.	ALA	BBB-	56.8%	4.55	4.55	12.1%	6.17
Canadian Utilities Limited	CU	BBB+	62.0%	3.50	3.67	11.3%	6.25
Emera Inc.	EMA	BBB	61.5%	3.06	3.28	8.1%	8.45
Enbridge Inc.	ENB	BBB+	54.3%	4.75	4.98	14.1%	5.46
Hydro One, Ltd.	H	A-	59.6%	4.90	4.92	12.5%	6.34
Canadian Proxy Group		BBB	55.0%	4.27	4.35	12.1%	6.35

Notes & Sources:
[1] Based on S&P's adjusted credit metrics for the holding companies.

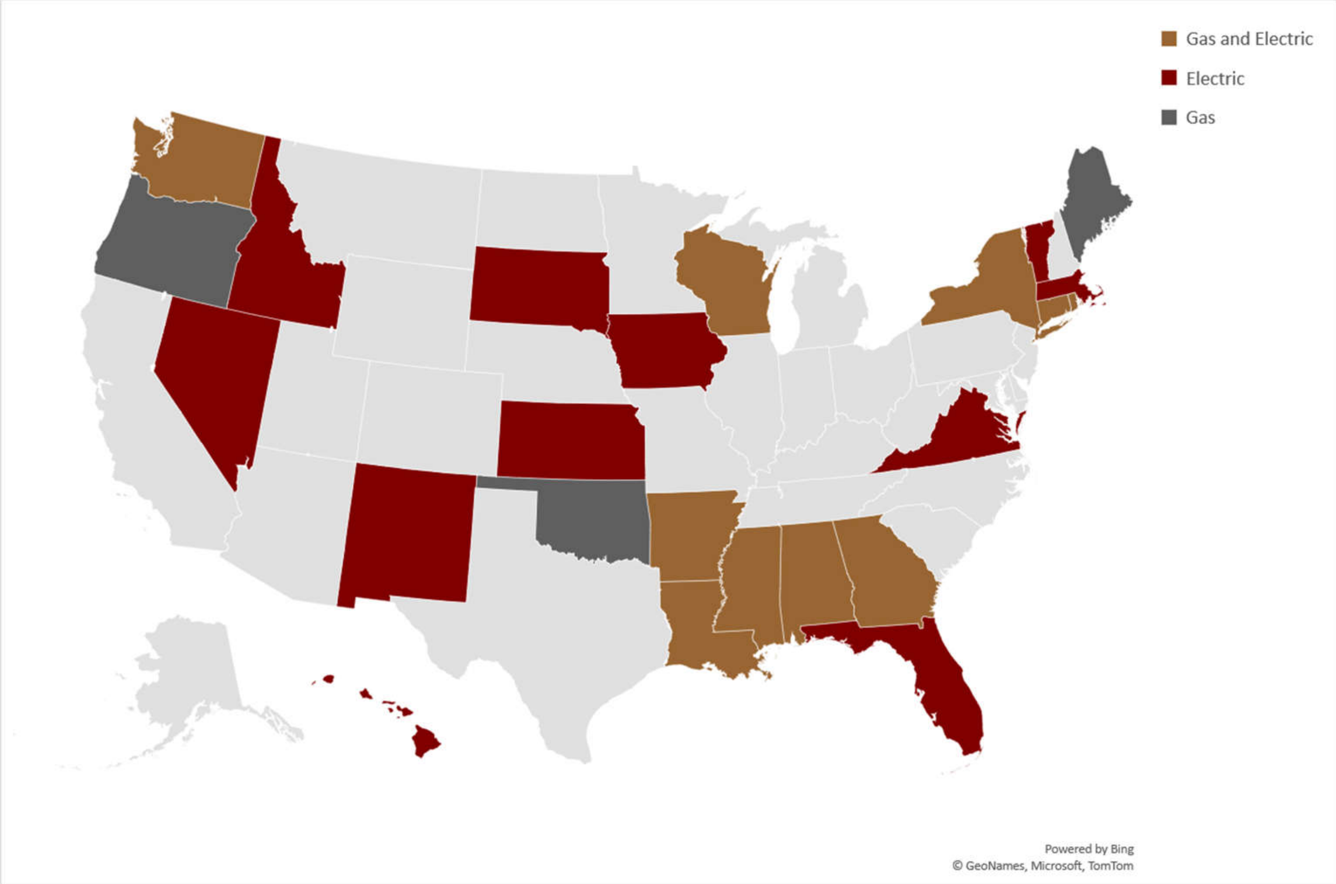
CANADIAN ESM PRECEDENT: EXAMPLES

Province	Company	Decision Type	Plan Term	ESM Parameters	Off Ramp/ Reopener	Note
Alberta	2nd Generation PBR	Fully litigated	2018-2022	None	(1) +/- 300 basis points above/below target ROE for two consecutive years (2) +/- 500 basis points/below target ROE for one year	
Alberta	ENMAX Power Corp. ("EPC")	Fully Litigated	2007-2016	+ 100 basis point dead band; 50/50 sharing thereafter; 100% downside risk to company	<u>Off-ramps</u> • circumstances change in a substantial or unforeseen manner • change in regulatory status • change in EPC control • misrepresentation by EPC Off-ramps would result in the Formula Based Ratemaking ("FBR") application being wholly re-opened or terminated <u>Re-openers</u> • failure to meet a specific performance standard for two consecutive years; • material changes in accounting standards that have an annual impact greater than $5 million; • expansion of EPC's service area where more than 10,000 customers are included within the expanded area; • actual ROE is +/- 300 bps above / below target ROE for two consecutive years; and • actual ROE is +/- 500 bps above / below target ROE for one year. The PBR would only be re-opened to the extent required to address the issue that triggered the re-opening	(1)
British Columbia	FortisBC (electric)	Fully litigated	2020-2024	Symmetrical +/- 50/50 sharing within a dead band	Post ESM earnings +/- 150 basis points for any one year	
Ontario	4th Generation Incentive Regulation	Fully litigated	Case-by-case	Case-by-case	A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels	
Ontario	Toronto Hydro	Fully litigated	2020-2024	+/-100 basis point dead band; 50/50 sharing on upside and downside (non-capital related variances)	A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels	(2)
Ontario	Hydro Ottawa	Settled	2021-2025	50/50 upside sharing; no dead band; downside risk to company	A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels	(2)
Québec	Hydro-Québec Distribution	Fully Litigated	2018-2021	50/50 upside sharing for the first 100 bps; 75/25 customer/company >100 bps; downside risk to HQD	A regulatory review ±125 basis points, post-ESM application	(3)
Newfoundland and Labrador	Newfoundland and Labrador Hydro	Settled	2020-2021	+/- 20 bps dead band around *RORB* (not ROE). Over earnings returned to customers, underearnings absorbed by Company.	None	

(1)	According to EPC, it interprets the application of the off ramp as post-ESM
(2)	Interpreted as pre-ESM given that this threshold applies to utilities in Ontario that do not have an ESM in their IR framework for two of the OEB's three IR frameworks
(3)	Distribution ESM was suspended early in transition to PBR until the Government of Quebec could return to a balanced budget

ESM PRECEDENT BY U.S. STATE

Precedent for earnings sharing exists in almost half of all U.S. states



Source: RRA as of March 2020

U.S. ESM PRECEDENT - EXAMPLES

State	Company	Decision Type	Plan Term	ESM Parameters	Off Ramp/ Reopener
MA	Eversource	Fully litigated	2018-2022	200 bps dead band; upside sharing 75/25% customer/company; no downside sharing	None; I-X
IL	ComEd & Ameren	State statute	2012-2022	+/- 50 bps dead band; 0/100 sharing above and below dead band until 2018. Dead band reduced to 0 after 2018 (all under/over earnings returned to or collected from customers)	None; I-X
NY	Consolidated Edison	Settled	2020-2023	50 bps dead band; 50/50 sharing >50 <100 bps; 25/75 sharing >100<150 bps; 10/90 sharing >150 bps	None; MRP
CT	United Illuminating	Fully Litigated*	2017-2020	50/50 upside sharing; 100% downside risk to company	None; MRP
HI	Hawaiian Electric	PUC determination	2021-2026	+/-300 bps dead band; 50/50 sharing +/- >450 <300 bps; 10/90 sharing >450 bps	+/- 450 bps or credit rating downgrade; I-X
ME	Maine Natural Gas	Settled	2016-2026	2017-2019: +/- 200 bps dead band; 50/50 sharing above and below dead band 2020-2024: +/- 250 bps dead band; 50/50 sharing above and below dead band	+500 bps only considered after 7th year of rate plan

* Unusual in CT; settlement more common

APPENDIX G

S&P Ratings Direct Report

on

Maritime Electric

dated May 11, 2021

S&P Global Ratings

Research

Maritime Electric Co. Ltd.

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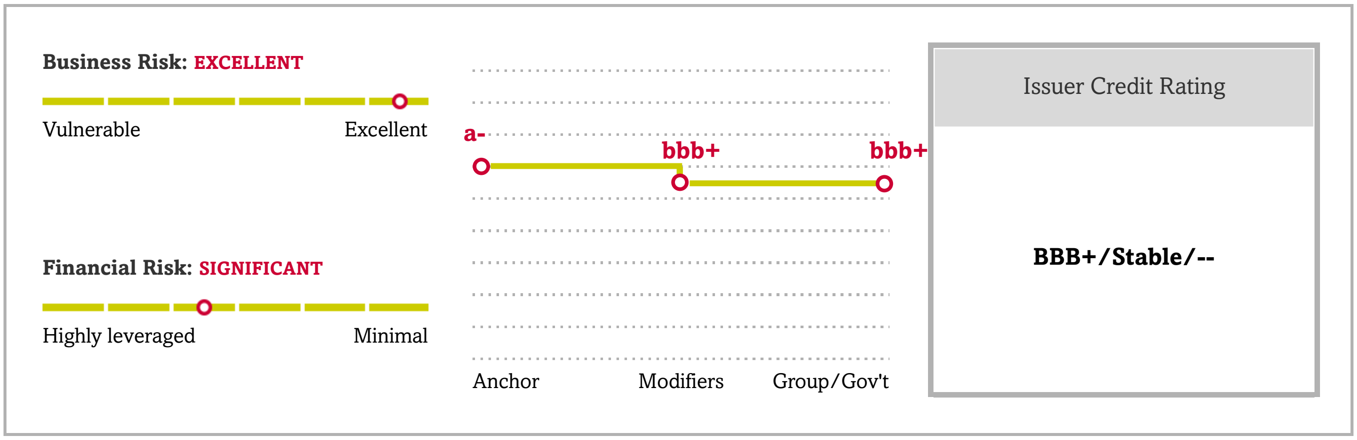
Maritime Electric Co. Ltd.



Credit Highlights

Overview

Key strengths	Key risks
Maritime Electric Co. Ltd. (MECL) operates as a low-risk integrated electricity generation, transmission, and distribution utility.	The company lacks geographic and regulatory diversity because it operates only in the province of Prince Edward Island (PEI). It also has a relatively small base of about 84,000 customers.
Regulatory framework is generally supportive with mechanisms, such as the energy cost adjustment mechanism, that minimize the utility's exposure to commodity input costs. There is also weather normalization in its rates, which reduces the utility's cash flow volatility due to changes in weather patterns.	Risk of political interference because the provincial government plays a significant and active role in establishing energy policy and setting rates for the island's customers.
A moderately strategic entity to its parent Fortis Inc., which we expect would provide extraordinary support under some foreseeable circumstances.	

The coronavirus pandemic had a minimal effect on MECL's operations and financials in 2020. We expect this trend to continue as the roll-out of COVID-19 vaccines progresses and the Canadian economy gradually recovers. In addition, because MECL's customer base is mostly residential, this also helps mitigate the pandemic's effect on the utility. Specifically, we expect increased consumption by its higher-margin residential customers, due to the rise in the number of people working from home, to offset the decline in its large commercial and industrial load consumption. This reinforces our favorable view of MECL's mostly residential customer base because their electricity consumption is fairly stable and less sensitive to economic cycles than that of its industrial customers.

The provincial government has a history of playing an active role in establishing energy policy and setting rates for the island's customers, which exposes the utility to potential political interference. We view this as generally less favorable than an independent regulator with a clear, consistent mandate and an established track record of credit-supportive policies.

MECL lacks geographic and regulatory diversity. Compared with its utility peers, the company has a small customer base and lacks geographic and regulatory diversity. Therefore, we consider MECL's business risk to be in the lower half of our excellent range relative to those of its utility peers and we ascribe a negative comparable rating analysis modifier to reflect this.

Outlook: Stable

The stable outlook on Maritime Electric Co. Ltd. reflects our view that it will continue to generate stable cash flow without experiencing any adverse regulatory or governmental rulings. During our two-year outlook period, we expect the utility to generate funds from operations (FFO) to debt of about 16%-17%.

Downside scenario

We could downgrade MECL over the next 12 months if its financial measures weaken, including FFO to debt of consistently below 15%.

Upside scenario

We could raise our ratings on MECL over a similar period if its financial measures improve, including FFO to debt consistently above 22%, assuming all else remains equal.

Our Base-Case Scenario

Assumptions

- No material effects from the coronavirus pandemic;
- The economy in its service territory remains stable with a modest increase in its customer base;
- No material adverse regulatory decisions;
- Capital expenditure of about C$50 million-C$70 million per year in 2021 and 2022; and
- Average annual dividends of C$10 million in 2021 and 2022.

Key Metrics

	2020a	2021e	2022f
FFO to debt (%)	17.36	16-17	16-17
FFO cash interest coverage (x)	3.99	About 4.0	About 4.0

a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

MECL is an integrated electricity generation, transmission, and distribution utility with operations throughout PEI. It provides services to more than 84,000 customers and is regulated by the Island Regulatory and Appeals Commission (IRAC). MECL is an indirect wholly owned subsidiary of Fortis Inc.

Business Risk: Excellent

Our assessment of MECL's business risk continues to reflect its lower-risk, rate-regulated, and vertically integrated electric utility business as well as its management of regulatory risk, which we view as consistent with that of its peers.

MECL is regulated by the IRAC, the regulator for the province of PEI, which we view as generally credit supportive because it allows the utility to timely recover prudently incurred operating and capital expenses. The IRAC's regulatory framework includes mechanisms, such as energy cost adjustments and weather normalization, that allow utilities to pass-through changes in their commodity costs to their customers and minimize the effects of weather on their electricity revenue, which provide stability to their cash flow. Further supporting our assessment of MECL's business risk is its customers, which are mostly residential consumers and small businesses (accounting for about 85% of its revenue) that are less sensitive to economic cycles. However, the company's lack of geographic and regulatory diversity, given that it only serves about 84,000 customers in the province of PEI, somewhat offsets these strengths.

In addition, the provincial government has a history of playing an active role in establishing energy policy and setting rates for the island's customers. We view this as generally less favorable than an independent regulator with a clear, consistent mandate and an established track record of credit-supportive policies. Due to the potential for political interference (which could impair the utility's credit quality) and the regulator's limited strength and independence, we view MECL's regulatory environment as less favorable compared with those of regulated utilities operating in other Canadian provinces. Taken together, we consider the utility's business risk profile to be in the lower half of its business risk profile category related to those of its utility peers.

Financial Risk: Significant

We assess MECL's financial risk profile using our medial-volatility financial benchmark table, which reflects the company's lower-risk regulated utility operations and effective management of regulatory risk.

Our analysis also incorporates the most recent rate decision from the IRAC in December 2020 that includes a rate increase of about 3% effective Jan. 1, 2021--Feb. 28, 2022. MECL deferred any changes to its electric rates in 2020 due to the pandemic's effect on the local economy. The rate decision also includes the recovery of the revenue shortfall from 2020 and the recovery of restoration costs related to Hurricane Dorian, which are offset by refunds of over-earnings through the rate of return adjustments.

Under our base-case assumptions that include the most recent rate case outcomes, capital spending of about C$50 million-C$70 million per year in 2021 and 2022, and dividends of about C$10 million per year, we forecast the company will maintain FFO to debt of about 15%-17% during our two-year outlook period.

Liquidity: Adequate

We assess MECL's liquidity as adequate. We expect the company's liquidity sources to be more than 1.1x its uses over the next 12 months and anticipate that its net sources will remain positive even if its EBITDA declines by 10%. In our view, MECL has sound relationships with its banks and a generally satisfactory standing in the credit markets. In the unlikely event of liquidity distress, we expect that MECL would scale back its capital spending and dividend payments to preserve its liquidity.

Principal Liquidity Sources	Principal Liquidity Uses
• Available committed credit facilities of about C$18 million as of Dec. 31, 2020; and • Cash FFO of about C$50 million over the next 12 months.	• Capital expenditure of C$50 million over the next 12 months; and • Dividend payments of about C$10 million over the next 12 months.

Debt maturities

- The company has no material debt maturities until 2024.

Environmental, Social, And Governance

MECL's environmental exposure is in line with that of its peers. The company is a vertically integrated utility; however, it purchases most of its power supply, about 75%, from neighboring province New Brunswick, including about 15% from the Point LePreau nuclear generation station and the remaining 25% from on-island wind assets. MECL has installed capacity of about 145 megawatts (MW) on PEI in the form of fossil-based oil and diesel generators, including about 55 MW from the Charlottetown Thermal Generating Station, which will be decommissioned in 2023-2024. However, these units are mainly used for backup. Therefore, the company's exposure to greenhouse gases is minimal.

From a social perspective, MECL's history of providing safe and reliable electricity to its customers could enable it to maintain social cohesion. We view the company's governance factors as neutral. Most of MECL's directors are independent of its owner, Fortis Inc. In our view, its board is capably engaged in risk oversight on behalf of all stakeholders.

Group Influence

MECL is an indirect wholly owned subsidiary of Fortis. We view the company as moderately strategic to Fortis's group, which reflects our view that it is unlikely to be sold, has the support of management, is reasonably successful at its operations, and is aligned with Fortis' overall business strategy. Based on our 'bbb+' stand-alone credit profile on MECL and our 'a-' group credit profile on Fortis, there is no uplift to our ratings on the company.

Issue Ratings - Subordination Risk Analysis

Capital structure

- As of Dec. 31, 2020, MECL's capital structure comprised about C$32.0 million of short-term borrowings and C$220 million of first-mortgage bonds (FMB).

Analytical conclusions

- MECL's FMBs benefit from a first-priority lien on the majority of the utility's real property owned or subsequently acquired. In addition, the collateral coverage on these FMBs is more than 1.5x, which supports a recovery rating of '1+' and an issue-level rating of 'A' (two notches above our 'BBB+' issuer credit rating on MECL).

Ratings Score Snapshot

Issuer Credit Rating

BBB+/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Negative (-1 notch)

Stand-alone credit profile : bbb+

- **Group credit profile:** a-
- **Entity status within group:** Moderately strategic (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- General Criteria: Hybrid Capital: Methodology And Assumptions, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of May 11, 2021)*

Maritime Electric Co. Ltd.	
Issuer Credit Rating	BBB+/Stable/--
Senior Secured	A
Issuer Credit Ratings History	
29-Mar-2016	BBB+/Stable/--
09-Feb-2016	BBB+/Negative/--
28-Oct-2014	BBB+/Stable/--

Ratings Detail (As Of May 11, 2021)*(cont.)	
Related Entities	
Caribbean Utilities Co. Ltd.	
Issuer Credit Rating	BBB+/Negative/--
Senior Unsecured	BBB+
Central Hudson Gas & Electric Corp.	
Issuer Credit Rating	A-/Stable/NR
Senior Unsecured	A-
FortisAlberta Inc.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured	A-
Fortis Inc.	
Issuer Credit Rating	A-/Stable/--
Preference Stock *Canada National Scale Preferred Share*	P-2
Preference Stock	BBB
Preferred Stock *Canada National Scale Preferred Share*	P-2
Preferred Stock	BBB
Senior Unsecured	BBB+
Fortis TCI Ltd.	
Issuer Credit Rating	BBB-/Stable/--
International Transmission Co.	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
ITC Great Plains LLC	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
ITC Holdings Corp.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured	BBB+
ITC Midwest LLC	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
Michigan Electric Transmission Co.	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
Tucson Electric Power Co.	
Issuer Credit Rating	A-/Stable/NR
Senior Unsecured	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

APPENDIX H

Energy Cost Adjustment Mechanism

Continuity Schedule

Monthly ECAM Schedules - January 1, 2021 to December 31, 2025

Energy Cost Adjustment Mechanism	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
Purchased Energy Costs	8,613,841	8,506,173	7,865,818	6,740,999	5,709,410	5,635,988	6,272,466	7,224,809	5,735,968	6,304,154	8,114,252	8,575,161	85,299,039
Lepreau Energy Costs	2,011,774	2,219,174	2,280,932	2,240,082	2,226,970	2,014,794	2,099,500	2,142,807	2,032,218	2,101,172	2,074,684	2,314,348	25,758,455
Generation Fuel Costs-PEI Plants	124,856	108,467	108,180	31,618	19,729	21,199	14,916	32,335	2,376	224,283	51,098	61,198	800,255
PEI Plant Operating Costs	255,378	244,126	298,914	260,981	253,000	244,887	270,352	234,519	229,514	258,919	230,072	248,637	3,029,298
Less: Insurance, Property Tax & Training	(85,685)	(80,893)	(96,328)	(82,353)	(75,966)	(83,453)	(91,637)	(70,702)	(88,097)	(88,377)	(88,097)	(88,097)	(1,019,682)
Amortization - Point Lepreau Writedown & DSM Program	21,700	21,700	21,700	21,700	21,700	21,700	21,700	21,700	17,327	17,327	17,327	17,327	242,907
Renewable Energy Costs	2,280,204	2,101,112	2,684,808	2,112,851	1,926,173	1,763,677	1,346,166	1,178,717	1,740,055	1,508,202	2,506,798	2,509,342	23,658,107
	13,222,068	13,119,859	13,164,025	11,325,878	10,081,017	9,618,793	9,933,462	10,764,185	9,669,362	10,325,681	12,906,134	13,637,915	137,768,378
Net Purchased & Produced Energy - kWh (NPP)	142,214,117	127,386,376	131,603,409	112,317,560	106,816,491	102,278,443	107,412,177	117,356,765	104,175,388	110,428,006	122,185,026	147,433,848	1,431,607,606
Base Rate/kWh	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244
Base Energy Costs	13,146,273	11,775,597	12,165,419	10,382,635	9,874,116	9,454,619	9,929,182	10,848,459	9,629,973	10,207,965	11,294,784	13,628,785	132,337,807
Difference Between Actual & Base Energy Costs	75,795	1,344,262	998,605	943,242	206,901	164,173	4,281	(84,274)	39,389	117,716	1,611,350	9,130	5,430,571
Opening Balance - ECAM	-	75,795	1,420,057	2,418,662	3,361,905	3,568,805	3,732,979	3,737,260	3,652,986	3,692,375	3,810,091	5,421,441	-
Additions/(Reductions)	75,795	1,344,262	998,605	943,242	206,901	164,173	4,281	(84,274)	39,389	117,716	1,611,350	9,130	5,430,571
Rebated/(Collected) From Ratepayer	-	-	-	-	-	-	-	-	-	-	-	-	-
Closing Balance - ECAM	75,795	1,420,057	2,418,662	3,361,905	3,568,805	3,732,979	3,737,260	3,652,986	3,692,375	3,810,091	5,421,441	5,430,571	5,430,571
Energy Sales - kWh	130,048,511	126,323,228	120,377,419	113,615,500	107,417,118	94,114,095	98,495,179	103,709,633	105,526,889	99,088,370	105,997,324	121,286,490	1,325,999,756
ECAM Adjustment Rate per kWh	-	-	-	-	-	-	-	-	-	-	-	-	
Rebated/(Collected) From Ratepayer	-	-	-	-	-	-	-	-	-	-	-	-	-

Energy Cost Adjustment Mechanism	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total
Purchased Energy Costs	9,177,840	8,269,998	7,128,730	7,985,162	8,322,073	6,576,291	7,463,552	7,703,447	6,368,241	7,290,820	7,819,345	8,999,729	93,105,228
Lepreau Energy Costs	2,071,313	2,077,107	2,087,819	1,652,170	1,685,165	1,956,003	2,129,280	2,195,142	2,141,566	2,150,204	2,162,106	2,221,375	24,529,250
Generation Fuel Costs-PEI Plants	166,514	76,983	76,983	24,803	24,803	6,000	26,872	26,872	6,000	24,803	24,803	166,514	651,949
PEI Plant Operating Costs	461,712	255,435	277,919	283,846	298,097	238,703	251,206	177,638	265,974	278,682	251,520	229,548	3,270,280
Less: Insurance, Property Tax & Training	(173,347)	(95,901)	(104,343)	(106,568)	(111,919)	(89,620)	(94,313)	(66,693)	(99,858)	(104,629)	(94,432)	(86,182)	(1,227,805)
Amortization - Point Lepreau Writedown & DSM Program	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	93,400
Renewable Energy Costs	2,339,518	2,159,639	2,757,035	2,134,070	2,022,622	1,840,664	1,410,073	1,240,906	1,804,088	1,567,057	2,603,546	2,592,422	24,471,639
	14,051,334	12,751,043	12,231,927	11,981,266	12,248,625	10,535,825	11,194,452	11,285,095	10,493,794	11,214,719	12,774,671	14,131,189	144,893,941
Net Purchased & Produced Energy - kWh (NPP)	154,070,651	138,174,471	129,746,866	116,951,011	114,387,627	105,211,216	117,126,008	118,242,965	106,592,694	116,470,309	135,242,532	151,981,763	1,504,198,113
Base Rate/kWh	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244	0.09244
Base Energy Costs	14,242,291	12,772,848	11,993,800	10,810,951	10,573,992	9,725,725	10,827,128	10,930,380	9,853,429	10,766,515	12,501,820	14,049,194	139,048,074
Difference Between Actual & Base Energy Costs	(190,957)	(21,805)	238,127	1,170,314	1,674,633	810,100	367,324	354,716	640,365	448,204	272,852	81,995	5,845,867
Opening Balance - ECAM	5,430,571	5,239,614	5,217,808	4,946,443	5,644,198	6,874,534	7,270,567	7,229,472	7,134,927	7,354,453	7,396,509	7,210,843	5,430,571
Additions/(Reductions)	(190,957)	(21,805)	238,127	1,170,314	1,674,633	810,100	367,324	354,716	640,365	448,204	272,852	81,995	5,845,867
Rebated/(Collected) From Ratepayer	-	-	(509,492)	(472,559)	(444,298)	(414,067)	(408,419)	(449,261)	(420,839)	(406,148)	(458,517)	(501,771)	(4,485,371)
Closing Balance - ECAM	5,239,614	5,217,808	4,946,443	5,644,198	6,874,534	7,270,567	7,229,472	7,134,927	7,354,453	7,396,509	7,210,843	6,791,068	6,791,068
Energy Sales - kWh	140,233,165	140,862,648	126,739,370	117,551,899	110,521,833	103,001,687	101,596,856	111,756,350	104,686,343	101,031,888	114,058,969	124,818,654	1,396,859,660
ECAM Adjustment Rate per kWh	-	-	0.00402	0.00402	0.00402	0.00402	0.00402	0.00402	0.00402	0.00402	0.00402	0.00402	0.00321
Rebated/(Collected) From Ratepayer	-	-	509,492	472,559	444,298	414,067	408,419	449,261	420,839	406,148	458,517	501,771	4,485,371

Monthly ECAM Schedules - January 1, 2021 to December 31, 2025

Energy Cost Adjustment Mechanism	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
Purchased Energy Costs	9,235,013	8,367,719	7,021,687	6,763,808	6,530,231	6,013,751	7,223,011	7,504,007	6,185,254	7,136,297	7,568,424	8,911,671	88,460,874
Lepreau Energy Costs	2,150,329	2,145,320	2,216,052	2,114,324	2,170,572	2,095,265	2,083,949	2,159,870	2,064,935	2,099,158	2,084,559	2,096,568	25,480,902
Generation Fuel Costs-PEI Plants	205,501	115,822	115,822	6,000	6,000	6,000	93,522	93,522	6,000	6,000	115,822	205,501	975,510
PEI Plant Operating Costs	456,175	252,371	274,586	280,442	294,522	235,841	248,193	175,507	262,784	275,340	248,504	226,795	3,231,060
Less: Insurance, Property Tax & Training	(187,800)	(103,898)											(291,698)
Amortization - Point Lepreau Writedown & DSM Program	7,783	7,783											15,567
Less: Excluded from ECAM per UE21-05 Appendix A*	-	-	(634,504)	(856,927)	(871,008)	(812,326)	(824,678)	(751,992)	(839,269)	(851,825)	(824,989)	(803,280)	(8,070,798)
Provincial Debt Repayment Cost	-	-	215,937	431,874	431,874	431,874	431,874	431,874	431,874	431,874	431,874	431,874	4,102,805
Renewable Energy Costs	2,470,470	2,302,439	2,934,426	2,357,983	2,260,707	2,068,000	1,645,130	1,458,646	1,995,568	1,728,229	2,722,473	2,690,500	26,634,572
	14,337,472	13,087,556	12,144,006	11,097,504	10,822,900	10,038,405	10,901,000	11,071,434	10,107,146	10,825,073	12,346,667	13,759,630	140,538,793
Net Purchased & Produced Energy - kWh (NPP)	153,704,996	137,600,953	129,019,262	115,624,496	114,066,177	105,246,821	116,591,988	117,878,032	106,043,200	116,350,922	135,406,972	151,180,651	1,498,714,470
Base Rate/kWh	0.09244	0.09244	0.09060	0.09060	0.09060	0.09060	0.09060	0.09060	0.09060	0.09060	0.09060	0.09060	0.09096
Base Energy Costs	14,208,490	12,719,832	11,689,145	10,475,579	10,334,396	9,535,362	10,563,234	10,679,750	9,607,514	10,541,394	12,267,872	13,696,967	136,319,534
Difference Between Actual & Base Energy Costs	128,982	367,724	454,861	621,924	488,504	503,043	337,766	391,684	499,632	283,680	78,795	62,663	4,219,259
Opening Balance - ECAM	6,791,068	6,358,191	6,161,836	6,002,992	6,055,636	6,008,858	6,012,898	5,858,408	5,708,666	5,701,063	5,495,243	5,021,594	6,791,068
Additions/(Reductions)	128,982	367,724	454,861	621,924	488,504	503,043	337,766	391,684	499,632	283,680	78,795	62,663	4,219,259
Rebated/(Collected) From Ratepayer	(561,858)	(564,080)	(613,705)	(569,280)	(535,283)	(499,002)	(492,255)	(541,427)	(507,235)	(489,500)	(552,444)	(602,560)	(6,528,629)
Closing Balance - ECAM	6,358,191	6,161,836	6,002,992	6,055,636	6,008,858	6,012,898	5,858,408	5,708,666	5,701,063	5,495,243	5,021,594	4,481,697	4,481,697

* Also excludes Provincial Debt Repayment Cost not proposed to be flowed through ECAM.

	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
Energy Sales - kWh	139,765,735	140,318,314	126,276,758	117,135,819	110,140,476	102,675,407	101,287,129	111,404,739	104,369,273	100,720,228	113,671,527	123,983,577	1,391,748,981
ECAM Adjustment Rate per kWh	0.00402	0.00402	0.00486	0.00486	0.00486	0.00486	0.00486	0.00486	0.00486	0.00486	0.00486	0.00486	0.00469
Rebated/(Collected) From Ratepayer	561,858	564,080	613,705	569,280	535,283	499,002	492,255	541,427	507,235	489,500	552,444	602,560	6,528,629

Energy Cost Adjustment Mechanism	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
Purchased Energy Costs	8,641,857	7,921,647	6,110,079	7,268,338	7,355,372	5,510,549	6,855,568	7,044,589	5,694,771	6,464,835	6,883,785	7,909,648	83,661,040
Lepreau Energy Costs	2,116,592	2,078,946	2,070,803	1,993,527	1,967,063	2,017,248	2,078,002	2,072,086	2,069,610	2,066,331	2,066,141	2,064,287	24,660,636
Generation Fuel Costs-PEI Plants	269,474	147,737	147,737	6,000	6,000	6,000	121,137	121,137	6,000	6,000	147,737	269,474	1,254,434
PEI Plant Operating Costs	282,144	282,144	282,144	281,710	271,139	271,139	271,139	271,139	271,139	271,139	281,710	273,497	3,310,185
Less: Excluded from ECAM per UE21-05 Appendix A*	(878,643)	(858,643)	(881,511)	(881,720)	(871,149)	(871,149)	(871,149)	(871,149)	(871,149)	(871,149)	(881,720)	(873,506)	(10,482,634)
Provincial Debt Repayment Cost	431,874	431,874	454,743	454,743	454,743	454,743	454,743	454,743	454,743	454,743	454,743	454,743	5,411,174
Renewable Energy Costs	3,414,569	3,386,627	4,052,780	3,279,988	2,919,889	2,804,296	2,202,530	2,090,438	2,707,710	2,635,557	3,770,011	3,922,239	37,186,635
	14,277,868	13,390,333	12,236,775	12,402,587	12,103,057	10,192,827	11,111,970	11,182,983	10,332,825	11,027,456	12,722,408	14,020,382	145,001,470
Net Purchased & Produced Energy - kWh (NPP)	155,390,422	143,815,988	128,100,173	115,958,082	115,068,961	106,283,057	118,364,897	118,042,468	107,080,986	118,423,520	138,202,389	152,692,128	1,517,423,073
Base Rate/kWh	0.09060	0.09060	0.09370	0.09370	0.09370	0.09370	0.09370	0.09370	0.09370	0.09370	0.09370	0.09370	0.09309
Base Energy Costs	14,078,372	13,029,729	12,002,986	10,865,272	10,781,962	9,958,722	11,090,791	11,060,579	10,033,488	11,096,284	12,949,564	14,307,252	141,255,002
Difference Between Actual & Base Energy Costs	199,496	360,605	233,789	1,537,314	1,321,096	234,104	21,179	122,403	299,336	(68,828)	(227,156)	(286,871)	3,746,468
Opening Balance - ECAM	4,481,697	3,990,914	3,658,579	3,487,137	4,648,675	5,616,401	5,521,484	5,218,238	4,983,963	4,948,893	4,557,237	3,965,597	4,481,697
Additions/(Reductions)	199,496	360,605	233,789	1,537,314	1,321,096	234,104	21,179	122,403	299,336	(68,828)	(227,156)	(286,871)	3,746,468
Rebated/(Collected) From Ratepayer	(690,278)	(692,940)	(405,231)	(375,776)	(353,369)	(329,022)	(324,425)	(356,678)	(334,407)	(322,828)	(364,484)	(397,098)	(4,946,537)
Closing Balance - ECAM	3,990,914	3,658,579	3,487,137	4,648,675	5,616,401	5,521,484	5,218,238	4,983,963	4,948,893	4,557,237	3,965,597	3,281,629	3,281,629

* Also excludes Provincial Debt Repayment Cost not proposed to be flowed through ECAM.

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
Energy Sales - kWh	142,032,551	142,580,221	128,237,772	118,916,503	111,825,763	104,120,798	102,666,028	112,872,932	105,824,902	102,160,880	115,343,068	125,663,841	1,412,245,259
ECAM Adjustment Rate per kWh	0.00486	0.00486	0.00316	0.00316	0.00316	0.00316	0.00316	0.00316	0.00316	0.00316	0.00316	0.00316	0.00350
Rebated/(Collected) From Ratepayer	690,278	692,940	405,231	375,776	353,369	329,022	324,425	356,678	334,407	322,828	364,484	397,098	4,946,537

Monthly ECAM Schedules - January 1, 2021 to December 31, 2025

Energy Cost Adjustment Mechanism	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Total
Purchased Energy Costs	7,656,546	6,675,435	5,231,166	5,043,878	5,483,942	5,047,150	6,415,148	6,532,831	5,077,467	5,929,207	5,917,251	6,911,079	71,921,101
Lepreau Energy Costs	2,145,510	2,143,112	2,142,576	2,140,798	2,139,642	2,137,864	2,136,708	2,135,241	2,133,463	2,132,307	2,130,529	2,129,372	25,647,122
Generation Fuel Costs-PEI Plants	299,079	163,664	163,664	6,000	6,000	6,000	134,074	134,074	6,000	6,000	163,664	299,079	1,387,297
PEI Plant Operating Costs	319,533	319,533	319,533	319,041	307,070	307,070	307,070	307,070	307,070	307,070	319,041	309,739	3,748,839
Less: Excluded from ECAM per UE21-05 Appendix A*	(939,556)	(919,556)	(919,556)	(921,070)	(909,099)	(909,099)	(911,058)	(911,058)	(911,058)	(911,058)	(923,029)	(913,727)	(10,998,923)
Provincial Debt Repayment Cost	454,743	454,743	454,743	454,743	454,743	454,743	454,743	454,743	454,743	454,743	454,743	454,743	5,456,910
Renewable Energy Costs	4,670,747	4,542,084	5,343,271	4,566,763	3,891,829	3,649,468	3,008,689	2,995,515	3,679,391	3,586,110	5,278,172	5,424,754	50,636,793
	14,606,602	13,379,014	12,735,396	11,610,153	11,374,126	10,693,196	11,545,373	11,648,415	10,747,076	11,504,378	13,340,370	14,615,039	147,799,139
Net Purchased & Produced Energy - kWh (NPP)	157,678,011	142,967,532	133,470,831	121,085,006	117,534,847	107,063,150	119,031,277	121,277,025	108,554,062	118,628,477	135,402,616	154,946,695	1,537,639,529
Base Rate/kWh	0.09370	0.09370	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09612	0.09565
Base Energy Costs	14,774,430	13,396,058	12,829,216	11,638,691	11,297,450	10,290,910	11,441,286	11,657,148	10,434,216	11,402,569	13,014,899	14,893,476	147,070,349
Difference Between Actual & Base Energy Costs	(167,828)	(17,044)	(93,820)	(28,538)	76,677	402,286	104,087	(8,733)	312,859	101,809	325,470	(278,437)	728,789
Opening Balance - ECAM	3,281,629	2,658,020	2,183,380	1,791,458	1,486,711	1,303,725	1,464,651	1,330,928	1,060,658	1,128,454	993,449	1,051,280	3,281,629
Additions/(Reductions)	(167,828)	(17,044)	(93,820)	(28,538)	76,677	402,286	104,087	(8,733)	312,859	101,809	325,470	(278,437)	728,789
Rebated/(Collected) From Ratepayer	(455,780)	(457,596)	(298,102)	(276,209)	(259,663)	(241,359)	(237,810)	(261,537)	(245,064)	(236,814)	(267,639)	(291,082)	(3,528,657)
Closing Balance - ECAM	2,658,020	2,183,380	1,791,458	1,486,711	1,303,725	1,464,651	1,330,928	1,060,658	1,128,454	993,449	1,051,280	481,761	481,761

* Also excludes Provincial Debt Repayment Cost not proposed to be flowed through ECAM.

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Total
Energy Sales - kWh	144,234,333	144,808,946	130,175,659	120,615,451	113,389,932	105,397,044	103,847,129	114,208,390	107,014,695	103,412,312	116,873,095	127,109,996	1,431,086,983
ECAM Adjustment Rate per kWh	0.00316	0.00316	0.00229	0.00229	0.00229	0.00229	0.00229	0.00229	0.00229	0.00229	0.00229	0.00229	0.00247
Rebated/(Collected) From Ratepayer	455,780	457,596	298,102	276,209	259,663	241,359	237,810	261,537	245,064	236,814	267,639	291,082	3,528,657

	Jan-26	Feb-26
Energy Sales - kWh	146,715,665	147,327,966
ECAM Adjustment Rate per kWh	0.00229	0.00229
Rebated/(Collected) From Ratepayer	335,979	337,381

APPENDIX I

Pro Forma Financial Statements

APPENDIX I
Maritime Electric
Financial Results (Actual and Forecast)
Statements of Earnings ($000s)

	Actual 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025
Net Revenue	225,258	234,179	249,257	261,903	273,871
Operating Expenses (net of ECAM)	163,852	172,661	179,246	187,995	195,856
Amortization - Fixed Assets	26,359	24,116	28,921	30,596	32,627
Amortization - Deferred Charges	243	93	173	189	189
Operating Income	34,804	37,309	40,918	43,123	45,199
Financing Costs	12,504	13,517	13,798	14,278	14,594
	73,910	75,035	83,809	88,186	92,609
Earnings Before Income Taxes	22,299	23,793	27,120	28,845	30,605
Income Taxes	7,120	7,429	8,459	8,994	9,538
Net Earnings - Regulated	$ 15,179	$ 16,364	$ 18,661	$ 19,852	$ 21,067
Fortis Inc Head Office Costs (net of tax) [1]	426	463	476	499	502
Net Earnings - Non-Regulated	$ 14,754	$ 15,901	$ 18,185	$ 19,353	20,564
Return on Average Common Equity (%) - Non-Regulated	8.93%	9.09%	9.70%	9.70%	9.71%
Return on Average Common Equity (%) - Regulated	9.35%	9.35%	9.95%	9.95%	9.95%

1 Costs disallowed in calculating the Annual Revenue Requirement and Regulated Return as per Order UE09-02

APPENDIX I
Maritime Electric
Financial Results (Actual and Forecast)
Balance Sheets

	Actual 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025
ASSETS					
Current Assets					
Accounts receivable	$ 29,147	$ 29,426	$ 30,187	$ 32,647	$ 34,227
Energy Cost Adjustment Mechanism	5,431	6,791	4,482	3,282	482
Materials and supplies	3,099	3,000	3,000	3,000	3,000
Prepaid expenses	723	702	715	725	730
	38,400	39,919	38,384	39,654	38,438
Fixed Assets					
Property, plant and equipment	692,024	731,172	775,864	838,370	899,634
Less: Accumulated amortization	234,037	241,760	249,435	263,752	277,575
	457,987	489,412	526,429	574,617	622,059
Other Long-Term Assets					
Regulatory Asset - CTGS Accumulated Reserve Variance	10,672	10,672	8,538	6,403	4,269
Weather Normalization Reserve Account	1,789	1,789	1,789	1,789	1,789
Regulatory Asset - OPEB	1,896	1,759	1,622	1,485	1,347
Intangible assets	4,053	4,150	4,300	4,450	4,600
Deferred charges	1,982	1,212	1,325	1,137	948
	20,393	19,583	17,574	15,264	12,953
TOTAL ASSETS	$ 516,781	$ 548,914	$582,387	$629,535	$ 673,450
SHAREHOLDER'S EQUITY AND LIABILITIES					
Current Liabilities					
Bank indebtedness	$ 3,583	$ 3,618	$ 303	$ 380	$ 3,330
Short-term borrowings	-	10,000	30,000	10,000	10,000
Rebates Payable to Customers	615	1,828	413	-	-
Accounts payable and accrued liabilities	29,724	30,358	30,883	30,516	31,980
	33,923	45,804	61,599	40,896	45,310
Long-term Debt	258,766	258,787	258,809	298,433	313,163
Other Long-Term Liabilities					
Employee future benefits	6,905	7,064	7,223	7,382	7,541
Future income taxes	25,440	30,121	35,826	42,056	48,828
Contributions	23,493	25,484	26,091	34,578	41,352
	55,839	62,669	69,141	84,016	97,722
Shareholder's Equity					
Common shares	31,101	37,101	38,601	41,101	41,101
Retained earnings	137,152	144,553	154,237	165,090	176,154
	168,253	181,654	192,838	206,191	217,255
TOTAL SHAREHOLDER'S EQUITY AND LIABILITIES	$ 516,781	$ 548,914	$582,387	$629,535	$ 673,450
Capital Structure - Year End					
Total Debt	60.9%	60.0%	60.0%	60.0%	60.0%
Common Equity	39.1%	40.0%	40.0%	40.0%	40.0%
	100.0%	100.0%	100.0%	100.0%	100.0%

APPENDIX I
Maritime Electric
Financial Results (Actual and Forecast)
Statements of Cash Flows

	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025
Cash Flow from Operating Activities					
Net Earnings	$ 15,179	$ 16,364	$ 18,661	$ 19,852	$ 21,067
Add (deduct) non-cash items:					
Amortization - Fixed Assets	26,359	24,116	28,921	30,596	32,627
Amortization - Deferred Charges	243	93	173	189	189
Amortization - Financing Fees	15	21	22	24	31
Future income taxes	1,122	4,681	5,706	6,230	6,773
Changes in non-cash working capital	156	374	679	(2,041)	2,686
	43,074	45,648	54,161	54,849	63,372
Cash Flow From Financing Activities					
Issuance (Repayment) of long-term debt	40,000	-	-	40,000	15,000
Contributions	1,670	3,538	2,250	10,250	8,750
Financing Fees	(301)	-	-	(400)	(300)
Payment of dividends - Regulated	(8,675)	(2,500)	(7,000)	(6,000)	(9,500)
- Non-regulated	(213)	(213)	(213)	(213)	(213)
	32,482	826	(4,963)	43,638	13,738
Cash Flow from Investing Activities					
Expenditures for Fixed Assets (Net)	(49,594)	(57,184)	(65,597)	(78,564)	(80,060)
Deferred Charges	2,028	677	(286)	-	-
	(47,565)	(56,507)	(65,883)	(78,564)	(80,060)
Increase (Decrease) in Cash	27,991	(10,033)	(16,685)	19,923	(2,950)
Bank Indebtedness, Beginning of Year	(31,575)	(3,584)	(13,617)	(30,303)	(10,380)
Bank Indebtedness, End of Year	($3,584)	($13,617)	($30,303)	($10,380)	($13,330)