All our energy.
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MARITIME ELECTRIC
A FORTIS COMPANY

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The Island Regulatory and Appeals Commission

November 3, 2023

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

Dear Commissioners:

Please find enclosed five (5) copies of Maritime Electric's Application for approval of a revised schedule of rates, tolls and charges for the periods March 1, 2024 to February 28, 2025, and March 1, 2025 to February 28, 2026 to recover the restoration costs related to Hurricane Fiona. 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

Gloria Crockett

Gloria Crockett, CPA, CA
Manager, Regulatory and Financial Planning

GCC31
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 3(a), 12(1), 12.1, 13(1), 20, 21(3)(a)(ii), and 24(1) 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 approving an adjustment to its rates, tolls and charges for electric service beginning March 1, 2024 for the Recovery of Hurricane Fiona Restoration Costs and for certain approvals incidental to such an order.

APPLICATION AND EVIDENCE OF MARITIME ELECTRIC COMPANY, LIMITED

November 3, 2023

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**BEFORE THE ISLAND REGULATORY
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IN THE MATTER of Sections 3(a), 12(1), 12.1, 13(1), 20, 21(3)(a)(ii), and 24(1) 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 approving an adjustment to its rates, tolls and charges for electric service beginning March 1, 2024 for the Recovery of Hurricane Fiona Restoration Costs and for certain approvals incidental to such an order.

Introduction

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.

Application

Maritime Electric hereby applies for an order of the Island Regulatory and Appeals Commission ("IRAC" or the "Commission") approving an adjustment to its rates, tolls and charges for electric service beginning March 1, 2024 for the Recovery of Hurricane Fiona Restoration Costs and for certain approvals incidental to such an order.

Procedure

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 3rd day of November, 2023.

D. Spencer Campbell, Q.C.

STEWART MCKELVEY
65 Grafton Street, PO Box 2140
Charlottetown PE C1A 8B9
Telephone: 902-629-4549
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 Section 3(a), 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 approving an adjustment to its rates, tolls and charges for electric service beginning March 1, 2024 for the Recovery of Hurricane Fiona Restoration Costs 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, Sustainability and Customer Operations for Maritime Electric Company, Limited ("Maritime Electric" or the "Company"), respectively, 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.

SWORN TO SEVERALLY at
Charlottetown, Prince Edward Island,
the 3rd day of November, 2023.

____

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 EXECUTIVE SUMMARY

3.1 Background

Late on Friday, September 23, 2022, Hurricane Fiona ("Fiona") passed by the east point of Prince Edward Island ("PEI"), impacting Maritime Electric Company, Limited ("Maritime Electric" or the "Company") customers Island-wide. The storm lasted approximately 12 hours with peak winds exceeding 130 kilometres per hour ("km/h") Island-wide, and reaching 150 km/h at East Point. Rainfall amounts exceeded 60 millimetres ("mm") Island-wide with 117 mm reported in Murray Harbour. The central pressure for Fiona was the lowest recorded barometric pressure to make landfall in Canadian history at 932.7 hPa, resulting in the most devastating natural disaster in the history of PEI.

Maritime Electric commenced restoration efforts when it was safe to do so at daybreak on Saturday, September 24, for the approximately 83,200 customers without power. It took 21 days to restore power to all customers that could have power restored. There were a number of customers with broken masts and access issues that had their power restored at later dates. The average customer outage duration as a result of the storm was 156.58 hours.

Fiona was the largest storm response in Maritime Electric's history utilizing 205 line crews, 59 vegetation management crews and many other supporting resources such as Canadian Armed Forces personnel, damage assessors, field supervisors, and traffic control personnel at the height of the restoration. Neighbouring utilities Nova Scotia Power, Newfoundland Power, and NB Power experienced damage and customer interruptions associated with Fiona and could not assist with Maritime Electric's restoration until their own restoration was completed. The Company engaged Fortis Inc. ("Fortis") resources from FortisBC, FortisAlberta, FortisOntario, Central Hudson, and Newfoundland Power, and other off-Island contractors.

It is estimated that over 40,000 fallen trees and branches had to be cleared from the electrical system in order for power to be restored. The vast majority of those trees fell from outside the right of way.[1] For this reason, the level of damage on the electricity system from Fiona would

[1] As indicated in the Company's Review and Report on Hurricane Fiona and Restoration, Docket UE12505, Exhibit M-5, a key learning identified was the need to widen existing rights of way in order to remove trees that pose the greatest risk during significant weather events.

not have been materially reduced had the Company invested additional resources into traditional vegetation management prior to the onset of Fiona.[2]

The transmission system suffered minimal structural damages, with only 10 transmission poles requiring replacement.[3] The distribution system required the replacement of 1,275 distribution poles, 445 transformers and 140 kilometres ("km") of conductor.[4]

3.2 Fiona Deferral

On November 25, 2022, the Company filed an application with the Commission for interim approval to defer the costs associated with the restoration of power due to damage caused by Fiona. This interim approval would allow the Company to properly recognize these costs at the end of its fiscal year and provide additional time in 2023 for the Company to accurately determine the allocation of costs between operating and capital activities, which impacts the potential recovery period. Further, an interim approval would provide sufficient time in 2023 for the Commission to fully review the Company's report on Fiona before granting final approval of the costs along with approval of a recovery period, as applicable. On December 19, 2022, the Commission issued Order UE22-08 providing interim approval to defer Fiona restoration costs.

In addition to the interim approval, Order UE22-08 included several regulatory requirements related to the interim deferral:

- Any and all government funding received by Maritime Electric shall be applied to reduce the balance of the interim deferral with any remaining balance to be recovered as directed by the Commission;
- The Company was not permitted to record any capital portion of the deferral to property plant and equipment;
- The Company was not permitted to include the interim deferral balance in its rate base or earn a rate of return on the balance deferred; and

2 The Company's Environmental Management Section permit from the Province of Prince Edward Island allows for the maintenance of the Provincial right-of-way ("ROW"). The Company's pole line is located along the edge of the ROW.

3 The Company currently has approximately 9,015 transmission poles installed on the Island's electrical system.

4 There are approximately 140,231 distribution poles currently installed on the Island's electrical system.

- The Company was required to file a comprehensive report to the Commission on the total costs incurred including supporting invoices, the proposed operating and capital allocation of the costs and an opinion from the Company's independent auditor confirming the total amount of Fiona-related costs incurred and that the proposed operating and capital allocation is consistent with the Company's policy.

In accordance with Order UE22-08, the Company filed a comprehensive review of its response to Fiona with the Commission on January 31, 2023 and, at the request of the Commission, a more detailed report was filed on March 7, 2023.[5] The second report included the supporting documentation requested by the Commission and the breakdown of operating and capital costs. The second report also included an audit opinion from the Company's independent external auditor on the total cost of restoration and that the allocation of capital and operating costs was in accordance with the Company's policy as required by the Commission. The audit report is provided as Appendix A to this Application.

In November 2022 Premier Dennis King indicated that government funding would be available to offset the restoration costs incurred by Maritime Electric.[6] The Company sent two letters, dated February 6, 2023 and May 1, 2023, to the Province of PEI (the "Province") seeking confirmation that Maritime Electric's restoration costs would be recovered through the Federal Disaster Financial Assistance Program ("FDFAP") or other government funding. These letters are provided in Appendix B to this Application.

More recently, the Premier indicated that the utility's costs do not qualify for funding under the FDFAP.[7] To date, the Company has not received any indication that government funding is forthcoming and is therefore submitting this application for final approval to recover the Fiona deferral balance which is estimated to be $37.0 million by February 29, 2024.[8]

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5 The January 31, 2023 report is Exhibit M-4 and the March 7, 2023 report is Exhibit M-5 under Docket 21505.

6 Isabell Gallant, CBC News, November 10, 2022. https://www.cbc.ca/news/canada/prince-edward-island/pei-maritime-electric-fiona-costs-federal-funding-1.6647068

7 Tarini Fernando, CBC News, August 22, 2023. https://www.cbc.ca/news/canada/prince-edward-island/ottawa-maritime-electric-costs-post-tropical-storm-fiona-1.6943389

8 The interim deferral balance of $34.6 million as of December 31, 2022 plus carrying costs of $1.5 million incurred up to September 30, 2023 and forecast additional carrying costs of $0.9 million up to February 29, 2024.

3.3 Proposed Recovery

The Company is seeking approval to record the capital portion of the costs incurred of approximately $19.3 million as Property, Plant and Equipment, in accordance with its capitalization policy, and recover this balance through depreciation expense at the applicable rates per the 2020 Depreciation Study.[9] As such, the capital portion would be recovered over the life of the related assets which is approximately 36 years, as discussed in Section 6.3 of this Application.

The Company is seeking approval to defer the operating portion of the costs incurred, of approximately $15.3 million, and the carrying costs incurred up to February 2024 of approximately $2.4 million, as a regulatory asset to be recovered over five years, as discussed in Section 6.4 of this Application.

Further, given that the restoration costs were necessary to restore service to customers as required under the *Electric Power Act*, were reasonable in the circumstances faced by the Company at the time of the event, and were prudently incurred, the Company requests approval to include these costs in rate base and finance it in accordance with its approved capital structure, as discussed in Section 4.4 of this Application.

Finally, the Company is seeking approval to issue sufficient common equity to its shareholder to restore the equity component of its capital structure to pre-Fiona levels to ensure the financial health of the Company is maintained, as discussed in Section 4.5 of this Application.

3.4 Customer Impact

The proposed recovery of the Fiona-related costs will result in an incremental annual cost increase of 2.4 per cent for benchmark customers.

A schedule of rates already approved for all customer classes effective May 1, 2023 and October 1, 2023 and the proposed rates for March 1, 2024 and March 1, 2025 is provided in Appendix C. These rates reflect the Commission Order UE24-04 approving the General Rate Application ("GRA") and the Energy Cost Adjustment Mechanism ("ECAM") Adjustment

[9] The 2020 Depreciation Study was approved by the Commission in Order UE23-04.

increase effective October 1, 2023 approved by the Commission in Order UE23-09 as well as the proposed adjustment to the approved basic rates to recover Fiona restoration costs proposed in this Application.

A summary of the proposed rates effective March 1, 2024 and March 1, 2025 including the adjustment to basic rates to recover the Hurricane Fiona Restoration Deferral Account is provided in Section 7.1 of this Application.[10]

[10] Rates for subsequent years will determined during the next GRA, which is expected to cover the rate-setting period of March 2026 to February 2029.

4.0 INTRODUCTION

4.1 Corporate Profile

Maritime Electric owns and operates a fully integrated power system providing for the purchase, generation, transmission, distribution and sale of electricity throughout 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. Through various contracts with the PEI Energy Corporation, the Company purchases the capacity and energy from 92.5 megawatts ("MW") of wind generation on PEI. In the event that the contractual agreements fail to provide all the energy required by customers, the Company owns and operates approximately 89 MW of on-Island backup generation.

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

4.2 Purpose

The purpose of this Application is to seek approval to recover Fiona restoration costs by increasing the Company's revenue requirement and basic rates effective March 1, 2024. This Application also provides evidence to support the inclusion of any unrecovered balance in the Company's rate base and its financing using the Company's approved capital structure.

4.3 Overview of Restoration Costs

Operating under the *Electric Power Act*, Maritime Electric has an obligation to provide service "at all times".[11] Therefore, when power outages occur, Maritime Electric must do whatever is necessary to repair any damage and restore power as quickly as possible. Such was the case when Fiona caused over 40,000 trees to come down across the Company's electrical system all across the Island. The restoration effort involved a substantial labour component that was necessary to remove all of the downed trees in order for crews to access and repair or replace the damaged power lines.

The Company's preparation for Fiona, the impact on the electrical system, the restoration effort, cost, and key learnings were documented in two reports filed with the Commission. A summary report was filed on January 31, 2023 and a more detailed report was filed on March 7, 2023.

The total cost to restore power to customers was $34.6 million, as summarized in Table 1.[12]

TABLE 1 Fiona Restoration Costs		
	($ millions)	**(%)**
Third-Party Contractor Labour	24.5	71
Maritime Electric Labour and Transportation	3.6	10
Materials	3.7	11
Accommodations, Meals, Travel, etc.	2.8	8
TOTAL[13]	**34.6**	**100**

Table 1 illustrates the labour intensive nature of the restoration effort, which was necessary to remove all of the fallen trees from the electrical system. The total cost was allocated to

11 Section 3(a) of the *Electric Power Act*.

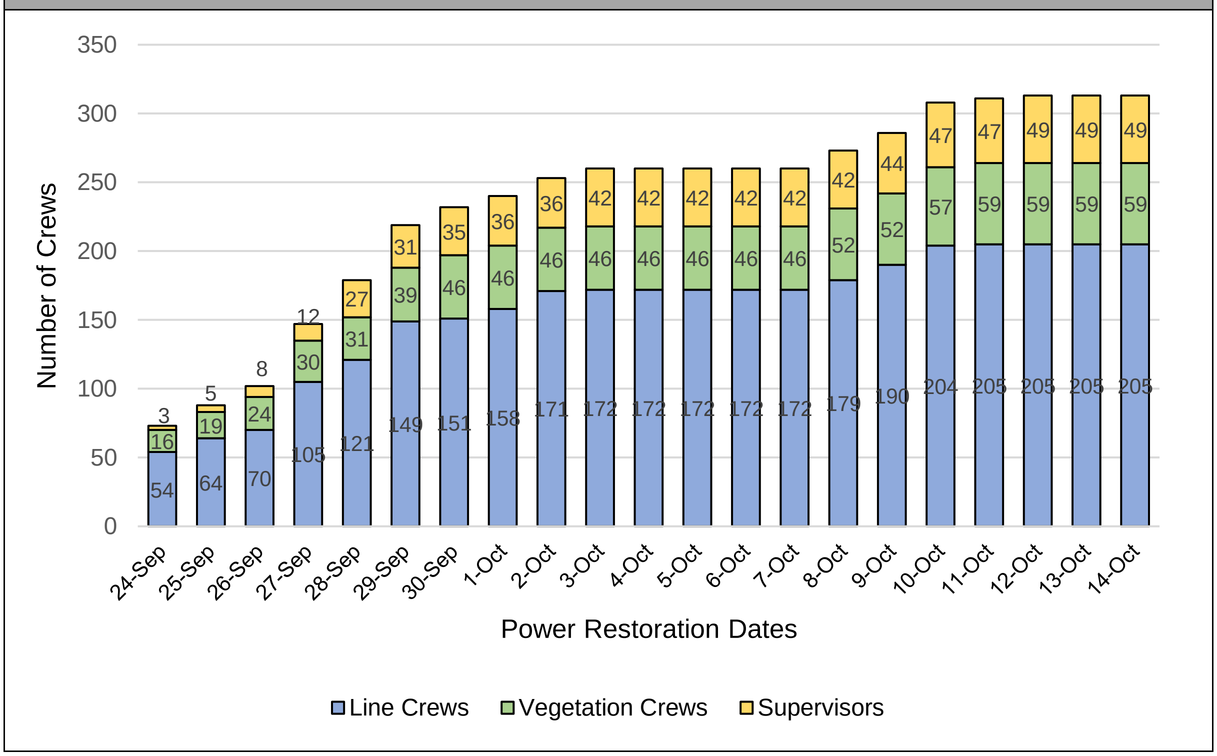
12 Table 1 herein is a summary of Table 14 included in the Company's Review and Report on Hurricane Fiona and Restoration filed with the Commission on March 7, 2023, Exhibit M-5.

13 The total cost presented is net of approximately $1.7 million in incremental vegetation and line maintenance costs expensed in the fourth quarter of 2022 that were attributable to Fiona-related system and vegetation maintenance activities.

operating and capital based on the nature of the work performed, with 55.8 per cent capital and 44.2 per cent operating.[14]

Prior to Fiona, Hurricane Dorian was the largest storm response in the Company's history, employing 80 crews at the peak of that restoration effort.[15] In preparation for Fiona, Maritime Electric had 70 crews standing by on September 24, 2022 to respond to Fiona-related power outages. Chart 1 demonstrates the continuous addition of more resources as the restoration effort continued, with a maximum of 205 line crews, 59 vegetation crews and 49 supervisors.[16] The continuous addition of resources also demonstrates the labour intensive nature of the work needed to be completed in order to restore power to all customers.

CHART 1
Field Resource Summary
Hurricane Fiona Power Restoration Resources



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14 The allocation between capital and operating was subject to independent review by Deloitte LLP, which was submitted as part of the Company's Review and Report on Hurricane Fiona and Restoration filed with the Commission on March 7, 2023, Exhibit M-5.

15 During its response to Hurricane Dorian, the Company began its restoration effort with 10 crews which increased to 80 crews at the peak of that restoration effort.

16 Chart 1 was originally included as Chart 6 of the Company's Review and Report on Hurricane Fiona and Restoration filed with the Commission on March 7, 2023, Exhibit M-5.

In addition to the restoration costs of $34.6 million outlined in Table 1, the Company is incurring approximately $0.2 million per month to finance the significant cash outlay related to these costs bringing the total deferral to $36.1 million as of September 30, 2023 and a forecast balance of $37.0 million by February 29, 2024.

4.4 Inclusion in Rate Base

As part of the regulatory compact as set out in the *Electric Power Act*, the Company has an obligation to serve all customers within its service territory at all times. In return, the utility is given an opportunity to earn a fair return on the shareholder's investment commensurate with the risk of investing in the utility.[17]

When a natural disaster strikes, a utility is expected to do what is necessary to repair the damage as quickly as possible. The cost of a massive effort including the mobilization of significant outside resources to restore power can be significant but is considered necessary when weighed against the societal cost of extending the duration of the outage experienced by customers.

The Company incurred these Fiona-related costs to restore service as part of its obligation to serve customers. These costs were prudently incurred and reasonable in the circumstances. As set out in the aforementioned regulatory compact, the Company therefore requests approval to recognize the capital, operating and carrying cost balances in its rate base and to earn the Company's approved rate of return on these balances.

4.5 Approved Capital Structure

The Company's approved capital structure is based on both equity and debt components. Under Section 12.1 of the *Electric Power Act*, the Company must "(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". In Order UE23-04, the Commission approved the Company's equity component of its capital structure at 40 per cent.

[17] Northwestern Utilities Ltd. vs Edmonton (City) [1929] SCR 186

Traditionally, the Company has maintained the common equity component of its capital structure between 39 and 40 per cent.[18] In August 2022, before the arrival of Fiona, the Company's equity component of its capital structure was 39.6 per cent. By December 2022, after the majority of costs related to Fiona restoration had been paid, the common equity component fell to 36.6 per cent and has remained largely unchanged throughout 2023 despite having suspended planned dividend payments to its shareholder in 2023.[19]

Before making investing decisions, debt and equity investors assess a company's financial risk (i.e., the risk associated with the way a company finances its business as evidenced by the relative percentages of debt and equity in its capital structure).[20] To the extent that a company is more highly leveraged, higher net income is required to cover fixed interest obligations, which must be paid before any net income is attributed to shareholders. If left unchecked, a sharp decline in a company's equity component of its capital structure, such as that experienced by financing the Fiona restoration costs entirely through debt, could result in a downgrade by credit investment agencies. This would immediately result in higher lending costs and eventually result in higher expected shareholder return, both of which are recovered from ratepayers.

The Company is, therefore, requesting approval to issue sufficient common equity to its shareholder, which is currently estimated to be up to $14.0 million, or 40 per cent of the restoration costs incurred, to rebalance its capital structure to the approved level.

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[18] The Company has increased or decreased planned dividends in order to maintain the equity component of its capital structure as close to 40 per cent as possible. The magnitude of the Fiona-related costs made it impossible for the Company to manage its capital structure solely by decreasing planned dividends.

[19] In the General Rate Application filed with the Commission on June 20, 2022, the Company forecast regulated dividends of $7.0 million in 2023, which was subsequently reduced to nil.

[20] Maritime Electric seeks investment financing through the issuance of first mortgage bonds from external investors and equity investment from its parent company.

5.0 RESTORATION COSTS

As discussed in Section 4.3 of this Application, a total of $34.6 million was originally deferred under the interim deferral Order UE22-08. Table 2 provides a breakdown of the capital, retirement and operating costs included in the interim deferral balance, as audited by Deloitte.

TABLE 2
Fiona-Related Costs[21]
($ millions)

	Capital and Retirement	Operating	Total
Third-Party Contractor Labour	13.3	11.2	24.5
Maritime Electric Labour and Transportation	2.3	1.3	3.6
Materials	3.7	-	3.7
Accommodations, Meals, Travel, etc.	-	2.8	2.8
TOTAL	**19.3**	**15.3**	**34.6**

An itemized spreadsheet of all costs included in this balance and supporting invoices were filed with the Commission with the Company's Review and Report on Hurricane Fiona and Restoration on January 31, 2023 and updated on March 7, 2023.

The third-party contractor labour cost is based on contract prices charged by the applicable contractor for a storm response. The Maritime Electric labour and transportation costs, and material costs are consistent with those presented in the Company's most recent General Rate Application ("GRA"). The accommodations, meals, travel and other logistics costs are based on prices charged by local providers of these services.[22]

Carrying costs, or short-term interest costs, of $1.5 million have been deferred bringing the total balance deferred to $36.1 million as of September 30, 2023. Carrying costs are based on the interest rates associated with the Company's credit facility, which were negotiated at a lower rate, as discussed in Section 5.3 of this Application.

[21] Table 2 excludes carrying costs.
[22] Maritime Electric was able to negotiate discounted rates with many of the local service providers.

5.1 Capital and Retirement Costs

Capital and retirement costs were associated with replacing damaged assets. The capital cost is associated with the installation of new assets and retirement cost is associated with removing the damaged assets. Fiona resulted in the replacement of 10 transmission poles, 1,275 distribution poles, 445 transformers, and 140 km of conductor, along with associated components (i.e., connectors insulators, cross arms, brackets, etc.).

In each instance of damaged assets, trees needed to be removed in order to safely access and replace the damaged assets.[23] The labour required to remove the trees during these instances was considered a capital cost and amounted to 81 per cent of the total capital cost.[24]

The storm response was labour intensive covering extended work days, several weekends and two statutory holidays which increased the overall hourly rates for all work associated with the asset replacements. This combined with the vegetation management cost required to remove trees, resulted in 42.7 per cent of the total restoration cost allocated to capital and 13.1 per cent allocated to retirement.

As discussed in Section 5.4 of this Application, the Company's external independent auditor provided an audit opinion that the proposed capital and operating allocation of the Fiona-related costs is in accordance with the Company's capitalization policy.

5.2 Operating Costs

Operating costs are associated with repairing damaged assets, versus capital costs that are associated with replacing damaged assets.

During the Fiona restoration, a significant portion of operating labour was associated with sectionalizing the power lines, which involves strategically and systematically isolating each circuit starting at the substation and then re-energizing each circuit working from the substation

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[23] With the exception of 12 poles that failed due to the wind impact alone (i.e., no interference from trees).

[24] Third-party contractor labour of $13.3 million plus Maritime Electric labour of $2.3 million equals $15.6 million divided by the total capital cost of $19.3 million equals 81 per cent.

to the end customer.[25] This approach is a utility best practice to ensure power is restored safely for utility workers and the general public.[26]

Maritime Electric has designed and equipped sections of the electrical system with protection devices (e.g., reclosers and fusing). Reclosers automatically try to restore power when there is a temporary fault. Reclosers are particularly effective when wind gusts push trees temporarily onto the power line. These devices will try to restore power three times and if the issue persists the device will remain open, at which point the circuit needs to be physically inspected and the recloser must be manually reset. Fuses are used to protect transformers and lines from faults, similar to fuse/breakers used to protect circuits in your home.

When faults occur on lines, reclosers and fuses activate to protect the utility's equipment and assist in preventing damage to customer equipment. During the Fiona restoration process, a significant amount of the labour was required to physically inspect all lines within the circuits to confirm faults were not present and lines were safe to be energized. Many tree contacts with lines occurred after power had been lost due to loss of transmission relatively early in the storm and the protection devices could not operate as normal. As a result, crews were required to systematically isolate lines, inspect them for faults and then close in the reclosers and fusing during the restoration process to avoid energizing lines with direct faults and creating unsafe work conditions. Extensive line faults were a direct result of the wide-spread tree damage caused during Fiona. If the inspection and power restoration revealed that no assets required replacement then the effort was considered an operating cost.

This circuit sectionalizing work lasted throughout the restoration process and combined with vegetation management and line repair activities resulted in 44.2 per cent allocation to operating costs.

[25] A circuit is a route through which electrical current can flow.

[26] The systematic isolation of each circuit before it is re-energized is particularly important to ensure the safety of the general public around downed power lines.

5.3 Carrying Costs

In addition to the costs incurred to restore power, the Company is incurring carrying costs associated with the cash outlay related to Fiona. These carrying costs were not known at the time the Company filed its GRA in June 2022 and thus were not included in the Company's forecast revenue requirement being recovered through current approved rates.

In accordance with Order UE22-08, which approved the interim deferral of Fiona-related costs, the Company was required to finance these costs entirely with debt, versus its approved capital structure of 60 per cent debt and 40 per cent equity. Initially, the Fiona-related costs were financed with the Company's $50 million unsecured revolving credit facility, which was increased in December 2022 to $90 million. When the Company increased the credit facility limit, it was also able to secure lower interest rates that continue to benefit customers today.[27]

In September 2023, the Company's credit facility borrowings were approaching the $90 million limit, requiring the Company to issue $60 million in first mortgage bonds to repay the credit facility borrowings.[28] At which point the $90 million limit was reduced back down to $50 million.[29]

As is the case with capital, retirement and operating costs, carrying costs were and are prudently incurred, and must be included in the recovery.

A summary of carrying costs incurred to September 30, 2023, as well as the forecast carrying charges until the recovery of Fiona begins in March 2024, is presented in Table 3.

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[27] Effective December 2022, the credit facility annual acceptance fee rate was reduced by 0.125% and the annual standby fee rate was reduced by 0.025%.

[28] The Commission approved this debt issuance in Orders UE23-07 and UE23-08.

[29] Reducing the limit avoids incurring additional financing costs as the credit facility agreement includes a stand-by charge for the unused portion of the credit facility limit.

TABLE 3 Carrying Costs		
Period	**Interest Rate (%)**	**Carrying Cost ($ millions)**
January – March 2023	5.86	$ 0.50
April 2023	5.75	0.17
May 2023	5.90	0.17
June 2023	5.71	0.17
July 2023	6.00	0.18
August 2023	6.17	0.18
September 2023	5.56	0.16
Forecast October 2023 to February 2024	5.56	0.84
TOTAL		**$ 2.37**

As per Section 6.4 of this Application, the recovery of the carrying costs should be the same as the recovery of the operating portion of the restoration costs.

5.4 Audit of Restoration Costs

In Order UE22-08 approving the interim deferral of Fiona-related costs, the Commission ordered the Company to provide an opinion from the Company's independent auditor confirming the total amount of Fiona-related costs deferred as of December 31, 2022 and that the proposed capital and operating allocation in accordance with the Company's capitalization policy. The audit report prepared by Deloitte LLP was filed with the Commission on February 28, 2023 and is provided for reference herein as Appendix A.

6.0 RECOVERY OF RESTORATION COSTS

This section evaluates the potential recovery periods for the Fiona-related costs.

6.1 Financial Stability

When large storms or other disasters damage electrical systems, utilities launch massive efforts to restore power as quickly as possible, and such efforts generally result in a substantial cost. A regulatory environment that facilitates the timely recovery of such costs from customers promotes the financial stability of the utility. This concept is discussed in a paper prepared by the Edison Electric Institute, After the Disaster: Utility Restoration Cost Recovery, which is provided as Appendix D.

Utilities are viewed as more risky when there is uncertainty whether prudently incurred storm-related costs will or will not be approved for recovery. This matters from the perspective that a utility with a higher risk rating incurs higher financing costs which are ultimately passed on to customers. Therefore, the timely recovery of storm-related costs helps ensure the financial stability of the utility and an appropriate risk rating, which benefits customers in the long-term.

For Maritime Electric specifically, its credit rating agency Standard & Poors ("S&P") has already indicated that the Company's risk is higher due to the lack of an approved storm deferral mechanism.[30] The inability to collect prudently incurred storm costs would be viewed negatively by S&P and could result in a downgrade to the Company's credit rating, which would ultimately increase the cost of both debt and equity financing.

The proposed recovery of Fiona-related costs in this Application seeks to balance the financial stability of the Company, which benefits customers in the long term, with the short-term rate impact on customers.

[30] The Company's S&P Ratings Direct Report dated July 10, 2023 is attached as Appendix E.

6.2 Government Funding

In November 2022, the media reported that Premier Dennis King had indicated that government funding would be available to offset the restoration costs incurred by Maritime Electric.[31] The Company sent two letters, dated February 6, 2023 and May 1, 2023, to the Province seeking confirmation that Maritime Electric's restoration costs would be funded by the government. These letters are provided in Appendix B to this Application.

More recently, Premier King indicated that the utility's costs does not qualify for funding under the FDFAP.[32] To date, the Company has not received any indication that government funding is forthcoming.

Should government funding be provided to Maritime Electric in the future, the Company will apply the funding to the unrecovered balance of the restoration costs. If future funding is not sufficient to fully offset the unrecovered balance, the Company herein proposes that the recovery approach approved by the Commission as a result of this Application continue until the Company files its next GRA. At which time the Company will provide an update on the remaining recovery period and when customer rates will need to be revised to avoid an over-collection of the restoration costs. If future funding is in excess of the unrecovered balance then the Company will file an application with the Commission proposing how the resulting balance should be refunded to customers.

6.3 Capital and Retirement Cost Recovery

As indicated in Section 5.0 of this Application, the capital and retirement portions of the restoration costs were $14.8 million and $4.5 million, respectively.

In accordance with generally accepted accounting standards and the Company's capitalization policy, these costs should be recorded as Property, Plant and Equipment and Accumulated Depreciation, respectively, and recovered from customers through annual depreciation

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[31] Isabell Gallant, CBC News, November 10, 2022. https://www.cbc.ca/news/canada/prince-edward-island/pei-maritime-electric-fiona-costs-federal-funding-1.6647068

[32] Tarini Fernando, CBC News, August 22, 2023. https://www.cbc.ca/news/canada/prince-edward-island/ottawa-maritime-electric-costs-post-tropical-storm-fiona-1.6943389

expense over the useful life of the related asset.[33] Using the depreciation rates approved by the Commission results in an annual increase in depreciation expense of $0.5 million. The calculation of this annual depreciation expense increase is provided in Appendix F.

6.4 Operating and Carrying Cost Recovery

Unlike capital costs which are recovered over the useful life of the related assets, generally accepted accounting standards would indicate that operating and carrying costs should be expensed in the period incurred. However, it is common utility practice to recover significant storm-related operating costs over a longer period of time to mitigate the rate impact on customers. This accepted practice seeks to balance the regulatory principles of rate shock and inter-generational equity.

Maritime Electric engaged Concentric Energy Advisors Inc. to research the recovery of storm-related costs in other jurisdictions. Table 4 provides examples of utilities that have deferred significant storm-related operating costs and the corresponding recovery periods.

TABLE 4
Examples of Utility Storm Deferrals and Recovery Periods

Utility	Major Storm(s)	Recovery Period(s)
New York State Electric and Gas	Super Storm Sandy Hurricane Irene Tropical Storm Lee	10 years and 5 years
Entergy Louisiana	Hurricane Katrina Hurricane Rita Hurricane Ike Hurricane Gustav Hurricane Isaac 2021 Winter Storm Uri	12 years
Liberty Missouri	2021 Winter Storm Uri	13 years
Puget Sound Energy	2012 snowstorm 2006 windstorm	6 years

[33] Costs that meet the definition of a capital asset must be recorded as a debit to Property, Plant and Equipment on the balance sheet. Costs incurred to remove damaged assets are considered retirement costs and must be recorded as a debit to Accumulated Depreciation on the balance sheet.

Table 4, along with other examples included in the Edison Electric Institute paper in Appendix D, illustrates that the determination of a reasonable recovery period is open to interpretation.

A shorter recovery period would achieve a lower total financing cost for customers, ensure that the majority of customers paying for the restoration are those who benefited from the restoration efforts, and provide the best cash flow for the financial stability of the utility. A shorter recovery period also results in a higher rate impact for customers. Maritime Electric considered a recovery period of 1 year, 5 years and 10 years, which are assessed as follows.[34]

Table 5 provides a comparison of the required increase in the 2024 revenue requirement under the three recovery periods, along with the corresponding increase in annual cost for a benchmark Residential Rural customer.[35]

TABLE 5
2024 Annual Revenue Requirement and Impact on Customers' Annual Costs

	1 Year	5 Years	10 Years
Total Increase in 2024 Annual Revenue Requirement ($ millions)	$ 19.5	$ 6.6	$ 4.9
Increase in Annual Cost for a Benchmark Residential Rural Customer (Fiona Recovery Only)	7.3%	2.4%	1.8%

The recovery of the capital and retirement costs, and associated income taxes, return on debt and return on equity is the same under each scenario and is based on the approved depreciation rates. Therefore, the differences under each scenario is attributed to the recovery of the operating and carrying costs under the three recovery periods.

One Year

As expected, a one-year recovery period for the Fiona-related operating and carrying costs results in the highest customer increase in annual cost. However, in the second year, the customer cost would decrease by 6.5 per cent as the operating and carrying costs are fully

[34] In each of the recovery period options presented, the recovery of the capital and retirement costs is in accordance with the approved depreciation rates.

[35] A benchmark Residential Rural customer consumes an average of 650 kWh per month.

recovered and customer rates would reflect the continued recovery of the remaining balance of capital costs.

Five Years

Increasing the recovery period to five years decreases the required increase in annual customer cost to 2.4 per cent versus 7.3 per cent for the one-year period. This scenario also results in the unrecovered balance being financed over the five-year period, thereby increasing the total amount to be recovered from customers.

Ten Years

Increasing the recovery period to ten years results in the lowest increase in annual customer cost at 1.8 per cent but also results in the unrecovered balance being financed over the longest period, resulting in a larger total amount being recovered from rate payers.

Recommended Recovery Period

In assessing each of the scenarios, the Company sought to principally balance the impact on customers' annual costs and limiting the total financing amount to be recovered from customers. The Company recommends the selection of a five-year recovery period for the following reasons.

First, with respect to a one-year recovery period, the Company respectfully submits that an increase in annual customer cost of this magnitude would introduce undue hardship for customers particularly when consideration is given to other rate changes that are approved for customers.[36]

The Company believes the ten-year recovery period is the least reasonable scenario when considering the probability that climate change may result in another significant weather event impacting PEI within the next ten years.

Therefore, the Company submits that the five-year recovery period is an appropriate balance.

[36] When combined with the GRA increase effective March 1, 2024 of 2.6% and the 1.6% increase for the ECAM rate adjustment effective October 1, 2024, the total increase in annual customer costs for rates effective March 1, 2024 would be 11.5% under a one-year collection scenario for operating and carrying costs.

7.0 CUSTOMER IMPACT

The Company is proposing to recover Fiona operating and carrying costs over five years as this option provides an optimal balance of managing the rate impacts to customers and recovering the costs over a reasonable period to manage total financing costs.

Table 6 details the components of the forecast 2024 annual revenue requirement based on the proposed recovery of Fiona restoration costs. The supporting calculations for Table 6 are provided in Appendix F.

TABLE 6
2024 Annual Revenue Requirement ($000)

Return on Debt	$ 865
Return on Equity	1,133
Subtotal – Return on Rate Base	**1,998**
Depreciation of Capital Costs	507
Amortization of Operating and Carrying Costs	3,533
Income Taxes	509
TOTAL	**$ 6,547**

Table 7 summarizes the revenue requirement to be recovered by customer class in basic rates.

TABLE 7
Forecast Sales and Annual Revenue Requirement to Recover Fiona Costs by Customer Class, March 1, 2024 to February 28, 2025

	Sales (MWh)	Revenue ($000)
Residential	788,118	$ 3,666
General Service	427,786	1,993
Large Industrial	168,125	397
Small Industrial	104,024	405
Street Lighting	4,025	71
Unmetered	2,590	15
TOTAL	**1,494,668**	**$ 6,547**

7.1 Proposed Customer Rates

Appendix C provides a schedule of existing customer rates, by customer class, effective May 1, 2023 and the proposed customer rates for October 1, 2023 and March 1, 2024 based on this Application. A summary comparison of the existing and proposed per kWh charge by customer class is provided in Table 8.

TABLE 8			
Energy Charge per kWh - Revenue Requirement (A)			
Customer Class	**Proposed Fiona Adjustment**	**Revised March 1, 2024**	**Revised March 1, 2025**
Residential - First Block	$ 0.0049	$ 0.1651	$ 0.1712
Residential - Second Block	0.0039	0.1306	0.1354
General Service - First Block	0.0061	0.2039	0.2114
General Service - Second Block	0.0039	0.1320	0.1368
Small Industrial - First Block	0.0059	0.1995	0.2068
Small Industrial - Second Block	0.0030	0.0989	0.1025
Large Industrial	0.0024	0.0821	0.0854
Energy Charge per kWh - Other Amounts (B)			
Description		**March 1, 2024**	**March 1, 2025**
Approved Order UE23-04		$ 0.0029	$ 0.0015
Proposed October 1, 2023 Adjustment Docket UE20605		0.0033	0.0033[37]
Total ECAM Charge per kWh		**$ 0.0062**	**$ 0.0048**
Provincial Energy Efficiency Program per kWh		0.0003	0.0012
Total Energy Charge per kWh – Other Amounts		**$ 0.0065**	**$ 0.0060**
Total Energy Charge per kWh (A+B)			
Customer Class		**March 1, 2024**	**March 1, 2025**
Residential - First Block		$ 0.1716	$ 0.1772
Residential - Second Block		0.1371	0.1414
General Service - First Block		0.2104	0.2174
General Service - Second Block		0.1385	0.1428
Small Industrial - First Block		0.2060	0.2128
Small Industrial - Second Block		0.1054	0.1085
Large Industrial		0.0886	0.0914

[37] In accordance with Order UE-09, an additional ECAM rate adjustment of $0.0033 per kWh will remain in effect until February 28, 2026 or until otherwise varied by the Commission.

7.2 Impact on Annual Customer Costs

The proposed adjustment to basic rates to recover Fiona restoration costs will increase the monthly energy charge per kWh as shown in Table 8 and Appendix C. This is in addition to the GRA rate adjustments approved in Order UE23-04 and the ECAM adjustment of $0.0033 per kWh approved in Order UE23-09. Other customer charges, namely the monthly service charges and demand charges, will remain unchanged.

The following three tables compare a benchmark customer's annual cost for the period March 1, 2023 to February 29, 2024 to the all-in annual cost increase effective March 1, 2024 to February 28, 2025. Both years reflect the impact of Orders UE23-04 and UE23-09, while the latter year also reflects the proposed impact of this Application.

Table 9 illustrates estimated annual cost, by component, for a benchmark rural residential customer using 650 kWh per month, or 7,800 kWh per year.

TABLE 9 Annual Cost for Rural Residential Customer (650 kWh per Month/7,800 kWh per Year)		
	Approved UE23-04 March 1, 2023 to February 29, 2024	**Proposed March 1, 2024 to February 28, 2025**
Service Charge	$ 323.04	$ 323.04
Basic Energy Charge	1,195.16	1,284.60
ECAM Charge	42.90	49.11
Provincial Debt Recovery	5.83	-
Provincial Energy Efficiency Program	2.13	2.47
RORA[38]	(13.24)	(0.63)
Sub-total	**1,555.82**	**1,658.58**
HST	233.37	248.78
Provincial Clean Energy Rebate[39]	(123.28)	(133.55)
Total Annual Cost	**$ 1,665.91**	**$ 1,773.81**
Percentage Annual Increase (%)		
Before Tax		**6.6%**
After Tax		**6.5%**

Table 10 illustrates the estimated annual cost, by component, for a benchmark urban residential customer using 650 kWh per month, or 7,800 kWh per year.

38 RORA refers to Rate of Return Adjustment.

39 The Provincial Clean Energy Rebate is a provincial Government rebate on the first block energy up to 2,000 kWh per month for eligible Residential year-round customers.

TABLE 10 Annual Cost for Urban Residential Customer (650 kWh per Month/7,800 kWh per Year)		
	Approved UE23-04 March 1, 2023 to February 29, 2024	**Proposed March 1, 2024 to February 28, 2025**
Service Charge	$ 294.84	$ 294.84
Basic Energy Charge	1,195.16	1,284.60
ECAM Charge	42.90	49.11
Provincial Debt Recovery	5.83	-
Provincial Energy Efficiency Program	2.13	2.47
RORA	(13.24)	(0.63)
Sub-total	**1,527.62**	**1,630.39**
HST	229.14	244.56
Provincial Clean Energy Rebate[40]	(123.28)	(133.55)
Total Annual Cost	**$ 1,633.48**	**$ 1,741.40**
Percentage Annual Increase (%)		
Before Tax		**6.7%**
After Tax		**6.6%**

Table 11 illustrates the estimated annual cost, by component, for a general service customer using 10,000 kWh per month, or 600,000 kWh per year, and demand of 50 kW per month, or 600 KW per year.

[40] The Provincial Clean Energy Rebate is a provincial Government rebate on the first block energy up to 2,000 kWh per month for eligible Residential year-round customers.

TABLE 11 Annual Cost for General Service Customer (10,000 kWh/50 KW per Month/120,000 kWh/600 KW per Year)		
	Approved UE23-04 March 1, 2023 to February 29, 2024	**Proposed March 1, 2024 to February 28, 2025**
Service Charge	$ 294.84	$ 294.84
Demand Charge	4,834.80	4,834.80
Basic Energy Charge	18,703.50	20,104.00
ECAM Charge	660.05	755.50
Provincial Debt Recovery	89.65	-
Provincial Energy Efficiency Program	32.75	37.95
RORA	(203.65)	(9.76)
Sub-total	**24,411.94**	**26,017.33**
HST	3,661.79	3,902.60
Total Annual Cost	**$ 28,073.73**	**$ 29,919.93**
Percentage Annual Increase (%)		
Before Tax		**6.6%**
After Tax		**6.6%**

Benchmark customers in the Small and Large Industrial classes will experience slightly larger increases in annual electricity costs than those presented for Residential and General Service Customers. This is due to the lower per kWh charge for the Large Industrial class and lower second block charge for the Small Industrial class, as the proposed increase to ECAM Rate Adjustment represents a larger percentage increase on these lower rates. The impact for each individual customer will vary depending upon each customers' demand and consumption profile. However, a reasonable estimate of the expected annual cost increase for Industrial customers is 7.7 per cent.

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 3(a), 12(1), 12.1, 13(1), 20, 21(3)(a)(ii), and 24(1) 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 approving an adjustment to its rates, tolls and charges for electric service beginning March 1, 2024 for the Recovery of Hurricane Fiona Restoration Costs and for certain approvals incidental to such an order.

WHEREAS on September 23, 2022, Hurricane Fiona ("Fiona") passed over Prince Edward Island causing extensive damage to the transmission and distribution system of Maritime Electric Company, Limited ("Maritime Electric" or the "Company");

AND WHEREAS on November 25, 2022, Maritime Electric filed an Application with the Commission requesting interim approval to defer the operating and capital costs associated with the Company's Fiona restoration effort;

AND WHEREAS on December 19, 2022, the Commission issued Order UE22-08 approving the deferral of the operating and capital costs associated with the Company's Fiona restoration effort;

AND WHEREAS on January 31, 2023, the Company filed with the Commission a summary report on its restoration efforts and filed a detailed report on March 7, 2023. The detailed report included the allocation of capital and operating costs, supporting invoices and an audit opinion from the Company's external auditor confirming the total balance and that the allocation of capital and operating is consistent with the Company's policy;

AND WHEREAS Maritime Electric was unable to obtain government funding to reduce its costs;

AND WHEREAS Maritime Electric continues to incur ongoing carrying costs of approximately $0.2 million per month;

AND WHEREAS Maritime Electric requests an order from the Commission granting approval for an adjustment to its rates, tolls and charges for electric service beginning March 1, 2024 for the Recovery of Hurricane Fiona Restoration Costs and for certain approvals incidental to such an order.

NOW AND THEREFORE pursuant to the *Electric Power Act* and the *Island Regulatory and Appeals Commission Act*, the Commission orders as follows:

IT IS ORDERED THAT

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

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

3. The Company shall record the capital and retirement portions of the Fiona restoration costs incurred to its Property, Plant and Equipment and Accumulated Depreciation in accordance with its capitalization policy and to recover these costs through previously approved depreciation rates.

4. The Company shall record all operating and carrying costs up to February 29, 2024, as a Regulatory Deferral and recover these costs over a five-year period beginning on March 1, 2024.

5. The Company shall include the capital and retirement costs included in its Property, Plant and Equipment and Accumulated Depreciation, and the Regulatory Deferral in its annual calculation of rate base and may earn up to its approved annual rate of return on its investment.

6. The Company is permitted to issue sufficient common equity to its shareholder to rebalance the equity component of its capital structure to pre-Fiona levels, not to exceed the legislated ceiling of 40 per cent common equity.

DATED at Charlottetown this ____ day of ____, 2023.

BY THE COMMISSION

_______________________________,
Chair

____
Commissioner

_______________________________,
Commissioner

Schedule of Hurricane Fiona restoration costs
Maritime Electric Company, Limited

December 31, 2022

Deloitte.

Deloitte LLP
816 Main Street
Moncton NB E1C 1E6
Canada

Tel: 506-389-8073
Fax: 506-632-1210
www.deloitte.ca

Independent Auditor's Report

To the Shareholder of
Maritime Electric Company, Limited

Opinion

We have audited the Schedule of Hurricane Fiona restoration costs of Maritime Electric Company, Limited (the "Company") as at December 31, 2022, and the notes to the Schedule (collectively referred to as the "Schedule").

In our opinion, the accompanying Schedule of the Company is prepared, in all material respects, in accordance with the basis of preparation described in Note 1.

Basis for Opinion

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

Emphasis of Matter – Basis of Accounting and Restriction on Use

We draw attention to Note 1 to the Schedule, which describes the basis of accounting. The Schedule is prepared to assist the Company to meet the requirements of the Island Regulatory and Appeals Commission (the "Commission"). As a result, the Schedule may not be suitable for another purpose. Our opinion is not modified in respect of this matter.

Responsibilities of Management and Those Charged with Governance for the Schedule

Management is responsible for the preparation of the Schedule in accordance with Note 1, and for such internal control as management determines is necessary to enable the preparation of the Schedule that is free from material misstatement, whether due to fraud or error.

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

Auditor's Responsibilities for the Audit of the Schedule

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

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

- Identify and assess the risks of material misstatement of the Schedule, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates, if any, and related disclosures made by management.

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

Deloitte LLP

Chartered Professional Accountants
Moncton, New Brunswick
February 24, 2023

Maritime Electric Company, Limited
Schedule - Hurricane Fiona restoration costs
Year ended December 31, 2022

	2022 $
Maritime Electric labour and transportation	3,564,523
Materials	3,692,221
Accomodations, meals, travel, etc.telecommunications, other	2,794,837
Third-party contractors:	
Holland Electric	4,914,775
Locke's Electric	2,186,686
NB Power	2,341,592
H-Line	2,041,106
Ontario Line Clearing	1,819,578
Newfoundland Power	1,422,638
Hydro-One	1,128,665
Atlantic Reach	1,025,498
GSD	1,024,948
Asplundh	961,910
Go With The Flow Traffic Control	1,019,468
Central Hudson	909,239
T&T Line Construction	880,384
Connect Atlantic	657,189
FortisAlberta	649,061
Saint John Energy	455,791
FortisBC	438,372
FortisOntario	351,639
Various Contractors	432,940
AVL Construction	279,756
Nightingale Tree Service	170,518
Safety First Traffic Control	153,106
Third-Party Recovery	(743,335)
	34,573,105
Capital	14,755,820
Retirement	4,522,970
Operating	15,294,315
	34,573,105

1. Basis of preparation

The Schedule of Hurricane Fiona restoration costs, which are categorized as operating, retirement or capital, is prepared in accordance with the Company's capitalization policy as disclosed in Note 2 and the interim utility order #UE22-08 issued by the Island Regulatory and Appeals Commission on December 19, 2022.

2. Capitalization policy

The Company's accounting guidelines and capitalization policy follow specifications and instructions from the Federal Energy Regulatory Commission, Department of Energy and Electric Plant Instructions. Property, plant and equipment ("PPE") are assets that are expected to have an economic useful service life beyond one year. Expenditures made to service PPE are capitalized when the expenditure provides a betterment to the asset and its service life is extended beyond its original expected service life. Once a PPE asset reaches the end of its useful service life, it is retired from service and the associated costs of removing the asset are charged to retirement.

All expenditures associated with development, engineering, acquisition or construction of the assets are accumulated and recorded as the cost of the asset when placed into service. Examples of cost include:

- Design, engineering and consulting;
- Internal labour and transportation costs;
- Contractor labour costs;
- Materials:
  - Materials purchased or constructed (i.e., transformers, substations, generating plants); and
  - Materials supplied by Maritime Electric Stores Inventory (i.e., poles, conductor line hardware and control devices);
- Legal and professional services; and
- Other directly attributable expenditures (i.e., travel, accommodations, meals).

When major adverse events or damage caused by weather, natural disasters, accidents or emergencies occur, and requires immediate restoration response, the Company capitalizes the installation of new equipment and certain vegetation management costs that are necessary to access the installation site. The Company measures the installation costs as the actual cost of the materials plus an allocation of labour. The labour allocation is based on historical experience installing similar equipment adjusted for emergency labour rate premium, travel and other costs.

For Hurricane Fiona, the Company applied the following policies to calculate the labour allocation:

	Normal Installation	Labour Premium	Fiona Installation
Material	30%		**19.67%**
Labour capital	49%	x 1.75	**56.23%**
Labour retirement	21%	x 1.75	**24.10%**

All other costs are expensed as operating.

All our energy.
All the time.

MARITIME ELECTRIC
A FORTIS COMPANY

February 6, 2023

Honourable Dennis King
105 Rochford Street, 5th Floor
Charlottetown PE C1A 7N8

Dear Premier King:

Hurricane Fiona Storm Restoration Costs

On September 23, 2022, Fiona passed through Prince Edward Island bringing heavy rains and strong winds gusting over 150 km/h to parts of the Province. Fiona far surpassed both Dorian and Juan in damage to PEI, and the effects were felt Island-wide. At the height of the storm, almost all Maritime Electric customers were without power and the sheer number of fallen trees during this storm made restoration work hazardous, complex and time consuming.

We are very proud of our response efforts given the enormous scale of this storm and the extensive damage that it caused Island-wide. The cost of the restoration effort was approximately $34.6 million.

Maritime Electric has prepared a detailed report on the restoration efforts ("Fiona Report"). The primary purpose of this report is to provide evidence to the Island Regulatory and Appeals Commission to support the recovery of these costs from customers, net of any Federal or Provincial funding that may be available.[1]

Through your discussions with the Prime Minister and representatives of the Federal Government, it has been indicated that there may be opportunity for some or all of the costs incurred to restore power on PEI to be funded through the Disaster Financial Assistance Program.

Please find enclosed three copies of the Fiona Report to support the application for funding through the Provincial-Federal Disaster Financial Assistance Program. Maritime Electric is committed to working with the Province to mitigate the financial impact of the Fiona restoration on customers. We look forward to further discussions on how we can support our customers and the Province through the Disaster Financial Assistance Program application process.

Yours truly,

MARITIME ELECTRIC

Jason Roberts
President & Chief Executive Officer

JCR03
Enclosure as noted

1 Maritime Electric received interim approval to defer all Fiona-related costs as a regulatory asset, with a subsequent application to be filed by mid-2023 proposing a plan to recover those costs, net of any government funding made available, from customers.

180 Kent Street • PO Box 1328 • Charlottetown, PE C1A 7N2
telephone 1-800-670-1012 • **fax** 902-629-3665 • **maritimeelectric.com**

All our energy.
All the time.

MARITIME ELECTRIC
A FORTIS COMPANY

May 1, 2023

Honourable Dennis King
105 Rochford Street, 5th Floor
Charlottetown PE C1A 7N8

Dear Premier King:

Hurricane Fiona Storm Restoration Costs

Seven months have passed since Hurricane Fiona wreaked havoc on Prince Edward Island resulting in extensive damage and considerable disruption of service to our customers. As indicated in a letter dated February 6, 2023, I am very proud of Maritime Electric's response efforts given the enormous scale of this storm and now Maritime Electric must proceed to recover the cost of the restoration which is $35.1 million.[1]

In your discussions with the Prime Minister and Federal representatives, it was indicated that the Disaster Financial Assistance Program may be an appropriate way to recover some or all costs associated with the power restoration to customers.

Without the Disaster Financial Assistance Program funding, the recovery of the $35.1 million from customers will increase electricity rates by approximately two to three percent, depending on the recovery period approved by the Island Regulatory and Appeals Commission.

Maritime Electric is committed to working with the Province of PEI, in a timely manner, to pursue any opportunities for Federal financial assistance to mitigate the impact on rates. As the restoration balance is accruing interest of approximately $170,000 per month, Maritime Electric must soon proceed with a cost recovery application and securing Federal financial assistance would be disclosed in the application.

We look forward to further discussions as soon as possible.

Yours truly,

MARITIME ELECTRIC

Jason Roberts
President & Chief Executive Officer

JCR07

[1] The restoration cost approximately $34.6 million and subsequent financing has cost $0.5 million, or approximately $0.17 million per month.

Maritime Electric Company, Limited
Schedule of Rates

Rate Code		May 1, 2023	October 1, 2023	March 1, 2024	March 1, 2025
110	**Residential Urban**				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 2,000 kWh	$ 0.1593	$ 0.1626	$ 0.1716	$ 0.1772
	Energy Charge per kWh for balance kWh	$ 0.1268	$ 0.1301	$ 0.1371	$ 0.1414
130	**Residential Rural**				
	Service Charge	$ 26.92	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1593	$ 0.1626	$ 0.1716	$ 0.1772
	Energy Charge per kWh for balance kWh	$ 0.1268	$ 0.1301	$ 0.1371	$ 0.1414
131	**Residential Seasonal**				
	Service Charge	$ 26.92	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1593	$ 0.1626	$ 0.1716	$ 0.1772
	Energy Charge per kWh for balance of kWh	$ 0.1268	$ 0.1301	$ 0.1371	$ 0.1414
133	**Residential Seasonal Option**				
	Service Charge	$ 37.50	$ 37.50	$ 37.50	$ 37.50
	Energy Charge per kWh for first 2,000 kWh	$ 0.1593	$ 0.1626	$ 0.1716	$ 0.1772
	Energy Charge per kWh for balance of kWh	$ 0.1268	$ 0.1301	$ 0.1371	$ 0.1414
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	$ 0.1958	$ 0.1991	$ 0.2104	$ 0.2174
	Energy Charge per kWh for balance of kWh	$ 0.1282	$ 0.1315	$ 0.1385	$ 0.1428
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	$ 0.1958	$ 0.1991	$ 0.2104	$ 0.2174
	Energy Charge per kWh for balance of kWh	$ 0.1282	$ 0.1315	$ 0.1385	$ 0.1428
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	$ 0.1917	$ 0.1950	$ 0.2060	$ 0.2128
	Energy Charge per kWh for balance of kWh	$ 0.0970	$ 0.1003	$ 0.1054	$ 0.1085
310	**Large Industrial**				
	Demand Charge per kW	$ 14.50	$ 14.50	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0809	$ 0.0842	$ 0.0886	$ 0.0914
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	$ 0.1041	$ 0.1074	$ 0.1130	$ 0.1165
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	$ 0.1062	$ 0.1095	$ 0.1152	$ 0.1187
	Energy Charge per kWh for balance of kWh in the month	$ 0.0882	$ 0.0915	$ 0.0960	$ 0.0987

Maritime Electric Company, Limited
Schedule of Rates

	Residential	Type		Annual kWh	Monthly kWh	May 1, 2023	October 1, 2023	March 1, 2024	March 1, 2025
	619	LED	70 W HPS Equivalent St Lights - Rented		15	$ 12.81	$ 12.86	$ 13.19	$ 13.55
	625	LED	100 W HPS Equivalent St Lights - Rented		17	$ 13.26	$ 13.32	$ 13.66	$ 14.03
*	630	HPS	St Lights - Rented	389	32	$ 17.00	$ 17.11	$ 17.55	$ 18.02
*	631	HPS	St Lights - Rented	553	46	$ 21.61	$ 21.76	$ 22.32	$ 22.92
*	632	HPS	St Lights - Rented	799	66	$ 30.90	$ 31.12	$ 31.92	$ 32.78
	633	HPS	St Lights - Rented	1283	106	$ 42.08	$ 42.43	$ 43.52	$ 44.69
	634	HPS	St Lights - Rented	1886	157	$ 49.35	$ 49.87	$ 51.15	$ 52.52
*	635	MV	St Lights - Rented	656	54	$ 16.93	$ 17.11	$ 17.55	$ 18.02
	639	Lanterns	City Lanterns - Rented	389	32	$ 62.13	$ 62.24	$ 63.85	$ 65.57
*	640	HPS	St Lights - Owned	389	32	$ 6.76	$ 6.87	$ 7.04	$ 7.23
*	641	HPS	St Lights - Owned	553	46	$ 8.93	$ 9.08	$ 9.31	$ 9.56
*	642	HPS	St Lights - Owned	779	65	$ 12.01	$ 12.22	$ 12.54	$ 12.87
	643	HPS	St Lights - Owned	1283	107	$ 19.04	$ 19.39	$ 19.89	$ 20.42
	644	HPS	St Lights - Owned	1886	157	$ 29.98	$ 30.50	$ 31.28	$ 32.11
	651	LED	St Lights - Owned	78	7	$ 1.22	$ 1.24	$ 1.27	$ 1.31
	652	LED	St Lights - Owned	246	21	$ 3.85	$ 3.92	$ 4.02	$ 4.13
	653	LED	St Lights - Owned	205	17	$ 3.21	$ 3.27	$ 3.35	$ 3.44
	666	LED	175 W MV Equivalent St Lights - Rented		25	$ 14.78	$ 14.86	$ 15.25	$ 15.65
	670	LED	St Lights - Rented	410	34	$ 17.21	$ 17.32	$ 17.77	$ 18.25
	675	LED	150 W/200 W HPS Equivalent St Lights - Rented		37	$ 16.01	$ 16.13	$ 16.55	$ 16.99
	719	LED	St Lights - Owned	176	15	$ 2.76	$ 2.81	$ 2.88	$ 2.96
*	730	HPS	Yard Lights - Rented	389	32	$ 17.00	$ 17.11	$ 17.55	$ 18.02
*	731	HPS	Yard Lights - Rented	553	46	$ 21.61	$ 21.76	$ 22.32	$ 22.92
*	732	HPS	Yard Lights - Rented	799	66	$ 30.90	$ 31.12	$ 31.92	$ 32.78
	733	HPS	Yard Lights - Rented	1283	106	$ 42.08	$ 42.43	$ 43.52	$ 44.69
	734	HPS	Yard Lights - Rented	1886	157	$ 49.35	$ 49.87	$ 51.15	$ 52.52
*	735	MV	Yard Lights - Rented	656	54	$ 16.93	$ 17.11	$ 17.55	$ 18.02
*	736	MV	Yard Lights - Rented	881	73	$ 21.53	$ 21.77	$ 22.33	$ 22.93
*	737	MV	Yard Lights - Rented	1210	100	$ 29.95	$ 30.28	$ 31.06	$ 31.89
*	740	HPS	Yard Lights - Owned	389	32	$ 6.76	$ 6.87	$ 7.04	$ 7.23
*	741	HPS	Yard Lights - Owned	553	46	$ 8.93	$ 9.08	$ 9.31	$ 9.56
	742	HPS	Yard Lights - Owned	779	65	$ 12.01	$ 12.22	$ 12.54	$ 12.87
	743	HPS	Yard Lights - Owned	1283	107	$ 19.04	$ 19.39	$ 19.89	$ 20.42
	744	HPS	Yard Lights - Owned	1886	157	$ 29.98	$ 30.50	$ 31.28	$ 32.11
	749	LPS	Yard Lights - Owned	869	72	$ 13.98	$ 14.22	$ 14.58	$ 14.97
	753	Flood	Yard Lights - Rented	1283	107	$ 40.18	$ 40.53	$ 41.58	$ 42.69
	754	Flood	Yard Lights - Rented	1886	157	$ 50.11	$ 50.63	$ 51.93	$ 53.32
	755	Halide	Yard Lights - Rented	1148	95	$ 42.24	$ 42.55	$ 43.65	$ 44.82
	756	Halide	Yard Lights - Rented	1878	156	$ 52.15	$ 52.66	$ 54.02	$ 55.47
	757	Halide	Yard Lights - Rented	4346	362	$ 89.89	$ 91.08	$ 93.42	$ 95.91
	759	Halide	St Lights - Owned	533	44	$ 8.35	$ 8.50	$ 8.71	$ 8.94
	760	Halide	St Lights - Owned	894	74	$ 14.02	$ 14.26	$ 14.63	$ 15.02
	761	Halide	St Lights - Owned	1148	95	$ 17.99	$ 18.30	$ 18.77	$ 19.27
	762	Halide	St Lights - Owned	1878	156	$ 29.41	$ 29.92	$ 30.69	$ 31.50
	764	LED	St Lights - Owned	410	34	$ 6.42	$ 6.53	$ 6.70	$ 6.88
	765	Halide	St Lights - Owned	759	63	$ 11.88	$ 12.09	$ 12.40	$ 12.73
	766	LED	St Lights - Owned	295	25	$ 4.62	$ 4.70	$ 4.82	$ 4.95
	775	LED	St Lights - Owned	438	37	$ 6.86	$ 6.98	$ 7.16	$ 7.35
	780	LED	St Lights - Owned	586	49	$ 9.18	$ 9.34	$ 9.58	$ 9.83
	785	LED	St Lights - Owned	718	60	$ 11.22	$ 11.42	$ 11.71	$ 12.02

* These charges are applicable to existing fixtures only.

Maritime Electric Company, Limited
Schedule of Rates

		May 1, 2023	October 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	$ 0.1913	$ 0.1946	$ 0.2055	$ 0.2123
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67	$ 11.67
820	12 Hour Lighting per kWh	$ 0.1913	$ 0.1946	$ 0.2055	$ 0.2123
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67	$ 11.67
830	24 Hour Lighting per kWh	$ 0.1913	$ 0.1946	$ 0.2055	$ 0.2123
	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	$ 0.1913	$ 0.1946	$ 0.2055	$ 0.2123
	Energy Charge per kWh for balance of kWh	$ 0.1171	$ 0.1204	$ 0.1231	$ 0.1270
		Currently no customers in this rate category			
	Short Term Unmetered Rates				
	Energy Charge:				
	per kWh of estimated consumption	$ 0.1913	$ 0.1946	$ 0.2055	$ 0.2123

	Single-Phase	Three-Phase
Connection Charge:		
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

EDISON ELECTRIC INSTITUTE

AFTER THE DISASTER:

Utility Restoration Cost Recovery

February 2005

Prepared by:
Bradley W. Johnson
ACN Energy Ventures LLC

Prepared for:
Edison Electric Institute
www.eei.org

Bradley W. Johnson is president of ACN Energy Ventures LLC, which provides independent energy consulting services to government, utility and power technology clients. Mr. Johnson is the former president of Pepco Technologies, a non-regulated utility subsidiary.

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701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Phone: 202-508-5000
Web site: www.eei.org

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EXECUTIVE SUMMARY

Several methods currently are used by utilities to lessen the financial impact of disaster restoration costs. But there is little consistency in how these methods are applied throughout the industry, or even within a company, from disaster to disaster. This creates uncertainty and invites political intervention. A formal and uniformly applied structure for disaster restoration cost recovery is needed.

When large storms or other disasters damage electric systems, utilities launch massive round-the-clock efforts to restore power as quickly as possible. The logistics associated with these restoration efforts can be daunting. In addition to deploying their own crews, utility companies must call upon crews from other parts of the country to help, with the "host utility" paying for wages, equipment rental, transportation, hotel rooms, meals and even laundry. Added to that are equipment costs, miles of new wire, thousands of new poles, new transformers, cross arms, fuses—the list goes on and on and so do the costs.

The key is restoring power as quickly as possible. Utilities mobilize outside resources at substantial additional costs in their effort to shorten the duration of power outages. When the final costs are tallied, the utility gets a bill that can be devastating financially.

Often there is not an established plan for how this bill will be paid. When the utilities meet with their regulators to discuss disaster restoration costs, the process often becomes highly politicized, and in at least one instance, the ensuing uncertainty has invoked a negative reaction from Wall Street.

To better understand the costs of disasters to utilities and their financial consequences, this report examines restoration cost data for 81 major storms that occurred between 1994 and 2004. The report also summarizes techniques used throughout the electric utility industry to mitigate the potentially devastating financial impacts of these storms and calls for the development of a more consistent and predictable method for recovering the cost of restoration when disaster strikes.

The Summary Points

- Utilities incur substantial costs to repair their systems after disasters strike. Based on survey data obtained for 81 major storms from 14 utility respondents, these disasters cost utilities approximately $2.7 billion (in constant $2003) between 1994 and 2004.

- The economic impact of not having electric service in an area hit by a disaster is much larger than the cost of repairing the damage. This suggests that the utilities' current practice of incurring additional costs to mobilize outside resources to restore power as quickly as possible is appropriate.

- The financial impact of disaster restoration can be devastating if it is not mitigated. For some companies, restoration costs can exceed net operating income for the year

- Several utilities rely on special storm reserves and/or deferred accounting treatment to lessen the financial impact of disasters.

- In at least one instance, Wall Street changed its credit outlook for a utility, in part because of concerns over how quickly a decision favorable to the utility would be reached to mitigate the financial impact of restoration expenses.

- There is little consistency in establishing which events do, or do not, qualify for disaster mitigation. For example, one company was required to expense approximately $160 million of O&M storm costs associated with a major hurricane against current year earnings, while another utility was allowed to recover a $1 million storm expense over a four-year period.

- Storm reserves provide a type of self-insurance to pay for major storms, however, they may not be funded sufficiently to pay for catastrophic storms. In most instances these reserves do not provide a ready source of cash to pay for storms.

- When faced with significant O&M restoration costs that could require a substantial write-off, many companies are granted permission by their commissions to defer these costs, but there is often a lengthy delay in providing this relief and the approval process can become politicized.

INTRODUCTION

Over a six-week period beginning Aug. 13, 2004, four hurricanes struck Florida. Never before in the state's history had so many hurricanes hit in a single season. The scale of the destruction caused by the storms was also unprecedented, with one in five homes suffering damage.

The impact on Florida's investor-owned electric utilities was equally destructive. The hurricanes required the state's investor-owned utilities to replace more than 3,000 miles of wire—enough to reach from Tampa to San Diego, almost 32,000 poles and more than 22,000 transformers. *(See Figure 1.)*

Figure 1
Florida 2004 Hurricane Damage[1]

	Poles Replaced	Transformers Replaced	New Conductor (Miles)
Hurricane Charley			
FPL	7,100	5,100	900
Progress Energy	3,820	1,880	667
Hurricane Frances			
FPL	3,800	3,000	550
Progress Energy	2,800	1,560	500
Hurricane Ivan			
Progress Energy	100	570	N/A
Gulf Power	5,060	3,175	225
Hurricane Jeanne			
FPL	2,300	3,000	250
Progress Energy	6,720	4,010	100
TOTAL	31,700	22,295	3,192

Source: Company reports
[1] Comparable storm damage data for Tampa Electric is not available

The combined storm costs totaled more than $1 billion for Florida Power & Light and Progress Energy alone. Uncertainty over how this bill would be paid caused Standard and Poor's to downgrade its outlook for Progress Energy from stable to negative, citing "uncertainties regarding the timing of hurricane costs" as one of the triggering events for the outlook revision.[1]

FPL fared better. It went into the hurricane season with approximately $345 million ($211 million in cash and $134 million in deferred taxes) set aside in a special storm reserve fund that it had established in the 1940s. Still, FPL was left with a repair bill of more than $545 million. Fortunately for FPL, the Florida Public Service Commission allowed it to carry the remainder of the unpaid storm bill as a negative balance in

[1] "Progress Energy Florida, Inc's Petition for Approval of Storm Cost Recovery Clause for Extraordinary Expenditures Related to Hurricanes Charley, Frances, Jeanne, and Ivan," Nov. 2, 2004, Florida Public Service Commission.

its storm fund thereby negating the earnings impact of the loss.[2] Questions remain on just how this bill will be paid and how the storm reserve will be refunded to provide a cushion for the next hurricane strike.

When the hurricanes struck Florida—and for that matter, whenever a major storm strikes—the affected utility is expected to mobilize a huge workforce to repair the storm damage as quickly as possible, with little or no consideration being given to the cost of the restoration effort.

There are vastly different policies in place around the country on how utilities recover these costs. In some cases, utilities are expected to pay for the costs and charge them against current year earnings. Had this been the policy in Florida, the financial consequences could have been devastating.

Paying for Storms in Hurricane Alley

FPL's service territory encompasses almost the entire east coast and parts of the west coast of Florida, making the company particularly vulnerable to damage from hurricanes. To help mitigate the financial impact of a catastrophic storm, FPL funds its storm reserves with cash payments invested in interest-bearing accounts. FPL is unique in the industry in this regard. This "funded" reserve minimizes the earnings impact of major storms and provides a source of cash to pay for storm costs.

In other instances, there appears to be an unwritten rule that when restoration costs become significant, the utility will be allowed to petition its utility commission to recover its prudently incurred costs by assessing its customers a surcharge or paying for the costs out of earnings over a fixed period of time, usually two to five years. There are also a number of companies, like FPL, whose commissions authorize the creation of special storm reserves that are credited each month. When disasters strike, these funds act as a form of insurance, mitigating the one-time financial impact.

The goal of this report is to look beyond Florida to assess the impact that disasters have on the broader electric utility industry and provide insight into how to pay the heavy price tag incurred as a result of these events. The report contains three major sections. The first summarizes a recent industry survey and provides a historical perspective on storm restoration costs. The second presents data showing the potential financial impact of these storms. The final section of the report looks at how storms are paid for and examines the accounting treatment for major storm costs and the cost-recovery policies that have been developed to help address the devastating financial impact of major storms on utilities.

[2] The Florida Public Service Commission also allowed Progress Energy, Tampa Electric and Gulf Power to carry negative balances in their storm reserve accounts.

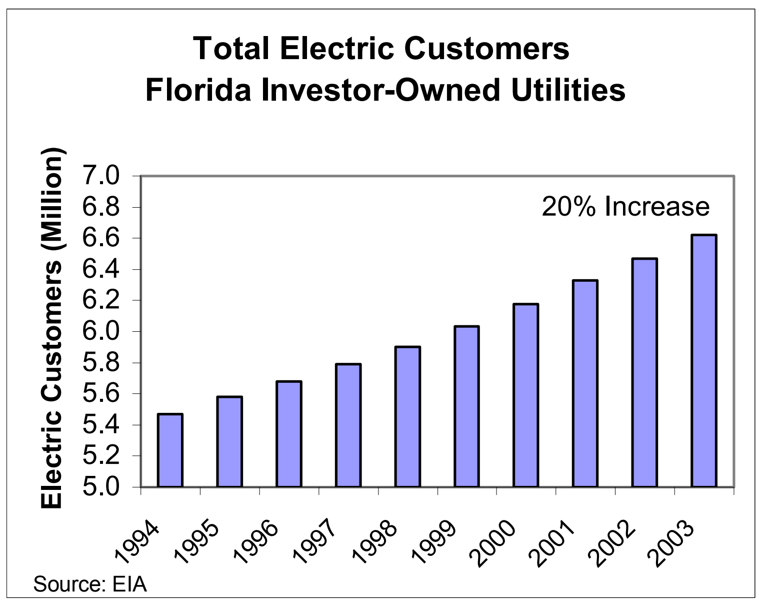
HISTORICAL PERSPECTIVE ON MAJOR STORM COSTS

To obtain a better understanding of the financial impact of major storms at a broader industry level, EEI member companies were asked to complete a survey providing information on storm costs and customer impacts. (*See sample survey in Attachment A, page 17.*) This data was then correlated with financial data obtained from FERC Form 1s to develop several key financial measures of the overall impact of major storms. Figure 2 provides a compilation of the data received from 14 companies for 81 major storms that caused almost $2.7 billion ($2003) in damage. (*See page 4.*)

Figure 3 summarizes major storm costs in constant $2003 obtained from the survey between 1994 and 2004. For the entire period, the average cost of a major storm was $48.7 million. The cost of an individual storm was as high as $890 million. If the five largest storms are deleted however, the average storm cost decreases by over 60 percent to $18.2 million. Four out of the five most expensive storms identified in the survey occurred since 2000 and three of those four were hurricanes. (*See page 5.*)

Increasing Storm Costs

In addition to the frequency and severity of a storm, another major driver in storm costs is customer growth. As populations expand, utilities are required to expand their electric systems to serve more new customers. As a result, even if the severity and frequency of storms remains consistent with historical levels, storm costs can be expected to increase simply because there is more electric equipment subject to damage from storms.



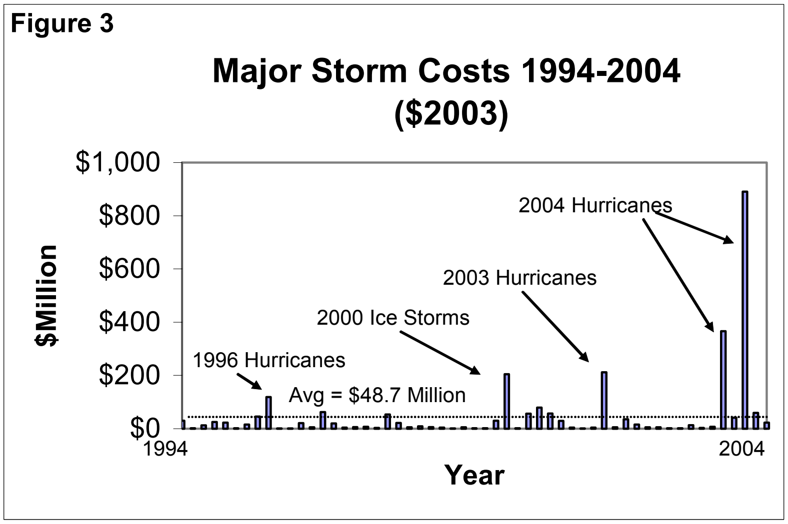
For example, during the 10-year period from 1993 to 2004, Florida utilities expanded their electric systems to serve approximately 1 million additional customers. This 20 percent increase in customers likely contributed significantly to the total costs Florida utilities incurred to repair their electric systems after the 2004 hurricanes.

Figure 2: Storm Survey Summary Results (Current Year $)

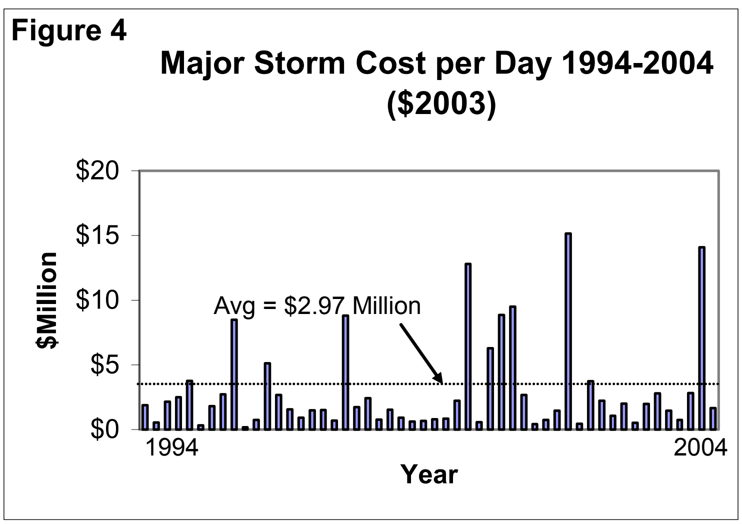
		Storm Data			FERC Form 1 Data	
Major Storm Event	Date	Outage Duration (Days)	Restoration Cost ($Million)	Accounting Treatment	T&D O&M Expenses ($Million)	Total Earnings From Electric Operations ($Million)
Ice Storm	Feb-94	16	$25.3	Reserve	$53.9	$216.6
Thunderstorm	Jun-95	4	$1.9	Expensed	$41.2	$167.0
WIND STORM & SNOWSTORM	Oct-96	6	$11.3	Deferral	$41.4	$177.9
Ice Storm	Nov-96	10	$21.8	Expensed	$45.7	$112.3
Snow/ice storm	Dec-96	6	$19.6	Deferral	$86.1	$200.6
WINTER STORMS	1996	6	$1.6	Expensed	$31.5	$66.9
HURRICANES & ICE STORM	1996	9	$14.1	Expensed	$147.7	$773.3
HURRICANE & ICE STORM	1996	17	$40.4	Expensed	$218.7	$858.5
HURRICANES	1996	14	$103.6	Deferral	$86.2	$514.1
Thunderstorm	Jun-98	2	$1.3	Expensed	$45.3	$184.2
Hurricane	Aug-98	4	$18.4	Deferral	$98.7	$604.0
Wind storm	Nov-98	2	$4.8	Expensed	$84.8	$218.1
Ice Storm	1998		$56.0	Deferred	$68.6	$98.6
HURRIANE & ICE STORM	1998	13	$18.1	Expensed	$169.3	$600.7
SUMMER STORMS	1998	5	$4.1	Expensed	$34.8	$115.5
Ice Storm	Jan-99	4	$5.4	Expensed	$176.1	$933.9
Ice Storm	Jan-99	5	$6.9	Reserve	$63.5	$138.5
Thunderstorm	Jul-99	5	$3.2	Expensed	$51.6	$224.5
Hurricane	Sep-99	6	$48.0	Deferral	$119.4	$589.4
HURRICANES	1999	13	$20.4	Expensed	$208.7	$751.4
WIND STORMS	1999	2	$4.4	Expensed	$93.4	$227.0
SUMMER & WINTER STORMS	1999	12	$8.4	Expensed	$36.5	$130.5
Ice Storm	Jan-00	4	$5.7	Expensed	$195.1	$824.4
Thunderstorm	May-00	4	$3.4	Expensed	$35.1	$65.3
Thunderstorm	Jul-00	2	$1.2	Expensed	$37.3	$142.2
SUMMER STORMS	Aug-00	8	$5.0	Expensed	$57.5	$139.6
Windstorm	Dec-00	2.9	$2.1	Expensed	$49.3	$143.6
Wind Storm	Dec-00	3	$2.3	Expensed	$88.3	$309.4
WINTER STORM & THUNDERSTORM	2000	13.5	$28.0	Expensed	$210.5	$945.9
ICE STORMS	2000	16	$190.0	Reserve	$78.8	$211.6
Thunderstorm	Jun-01	3	$1.6	Expensed	$62.1	$196.7
Ice Storm	Jan-02	9	$54.7	Deferral	$62.1	$196.7
Ice Storm	Dec-02	9	$77.0	Expensed	$259.5	$895.3
Ice Storm	Dec-02	6	$55.0	Deferral	$145.1	$663.1
HURRICANE & TROPICAL STORM	2002	11	$28.4	Reserve	$21.0	$85.6
WINTER STORMS	2002	11	$4.5	Reserve	$32.5	$51.4
Wind/tornado	May-03	2	$1.4	Expensed	$62.1	$196.7
Tropical Storm	Jun-03	3	$4.3	Reserve	$35.7	$84.2
Hurricane	Sep-03	14	$208.5	Expensed	$293.4	$853.9
WIND STORMS & THUNDERSTORM	2003	11	$4.7	Expensed	$41.9	$32.1
HURRICANE, WIND & ICE STORMS	2003	9.5	$34.9	Expensed	$275.4	$892.8
WIND STORMS	2003	7	$15.2	Deferral	$101.2	$213.3
Wind Storm	Jan-04	5	$5.4	Expensed	$101.2	$213.3
Wind Storm	Mar-04	2.5	$5.0	Expensed	$275.4	$892.8
Thunderstorm	Jun-04	3	$1.6	Expensed	$62.1	$196.7
Hurricane	Sep-04	3	$0.6	Reserve	$35.7	$84.2
Wind Storm	Dec-04	1	$2.0	Expensed	$95.3	$195.7
Ice Storm	Dec-04	5	$14.0	Reserve	$67.0	$223.0
Wind Storm	Dec-04	2	$2.9	Deferral	$101.5	$199.2
SUMMER STORMS	2004	10.1	$7.6	Expensed	$40.6	$119.3
HURRICANES	2004		$890.0	Reserve	$291.6	$917.7
HURRICANES	2004	15	$42.2	Deferral*	$119.0	$830.5
HURRICANES	2004	26	$366.4	Reserve	$120.6	$352.0
HURRICANES	2004		$60.0	Reserve	$45.4	$212.6
ICE STORM & SUMMER STORMS	2004	14	$23.1	Deferred	$70.4	$196.2

Note: CAPITALIZED STORMS indicate multiple major storms in a year

**Assumes storm costs deferred based on commissions prior treatment of costs for major storms*

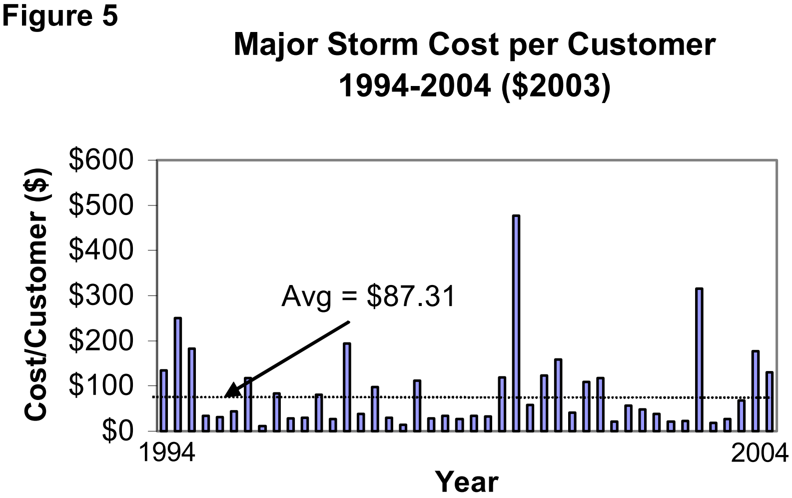


For another perspective on storm costs, consider that on average, utilities spent almost $3 million a day (constant $2003) to repair their systems, but several storm costs exceeded the $10 million per day range (*Figure 4*).



A final perspective on historical storm costs is obtained by calculating storm costs per customer. Figure 5 compares the total costs of the storm (in constant $2003) to the peak number of customers affected by the storm.[3] Average storm cost per peak customer from 1994 to 2004 was approximately $87—about the same amount of revenue that a utility receives each month from a typical residential customer.

Figure 5



Several important conclusions can be drawn from the historical data presented in these charts:

1. Based on the sample of storm data obtained from the surveys, it is evident that utilities incur substantial costs to repair their systems after major storms. Total storm costs between 1994 and 2004 were approximately $2.7 billion ($2003). A large portion of this cost is the result of the huge damage inflicted by a handful of storms that have occurred since 2000.
2. The magnitude of storm restoration costs appears to be random and varies greatly with the type and severity of storms.
3. Utilities mobilize substantial resources to repair their systems after major storms, as is evidenced by the rate at which utilities incur costs during a storm restoration.
4. Average utility storm restoration costs are significant from both a customer and a utility perspective as measured by a storm's cost per customer.

[3] "Peak customers" is used instead of "total customers" because total customers includes customers that incur power outages resulting from utility restoration efforts that may not be related to the storm, e.g. feeder switching.

DETERMINING THE POTENTIAL FINANCIAL IMPACT OF MAJOR STORMS

At an industry level, little is known about the financial impact of major storms. Based on recent media reports of major storms, the potential financial impacts are substantial, even catastrophic.

To better gauge the potential financial impact of major storms, let's examine the impact that very large storms occurring since 2000 had on four companies. Figure 6 evaluates company transmission and distribution (T&D) expenses and net earnings using data from media accounts of storm costs and FERC Form 1 financial data to compare the cost (including capital) of four large storms that occurred since 2000.

The data indicates that storm costs can have a large and potentially devastating financial impact. In some instances, storm costs exceed a company's total earnings and T&D expenses for the entire year.

Figure 6

Storm Description	Date	Storm Cost $Million ($2003)	Financial Impact: % of Annual T&D Expenses	Financial Impact: % of Net Operating Income
Progress Energy NC Ice Storms	2000	$ 205	259.8%	96.7%
Dominion Energy Hurricane Isabel	2003	$ 212	72.3%	24.8%
Progress Energy Florida Hurricanes	2004	$ 366	303.8%	104.1%
FPL Hurricanes	2004	$ 890	305.2%	97.0%

Source: Press Accounts and FERC Form 1 Data

To assess the potential financial significance of major storms, storm-cost data was compared to net utility operating income and T&D expenses for each company that reported a major storm. *(See Figure 2, page 4.)* If a company reported more than one major storm in a year, the storm costs were combined. These results are summarized in the following charts.

Figure 7 compares storm costs to income and indicates that storm costs could have a significant impact on a utility company's earnings if all of the storm's cost were written off against current earnings. Average storm costs for the 1994-2004 period were approximately 13 percent of net utility operating income. (*See page 8.*)

The chart also indicates considerable volatility from year to year in the potential earnings impact of major storms. In many years, storm costs were significantly less than the 13 percent average, but in other years costs were significantly above average. For three storms, costs nearly equaled the company's operating income for the entire year.

Figure 7

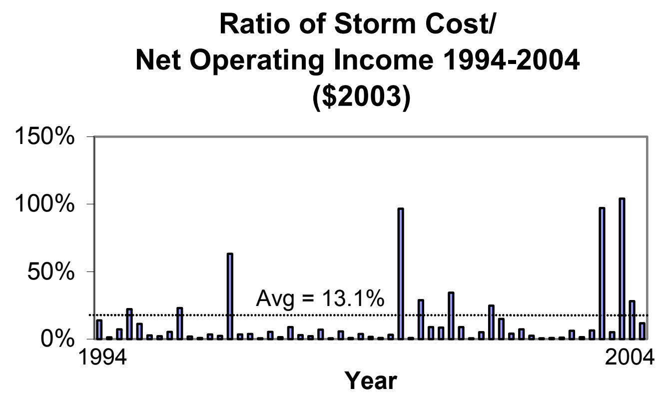
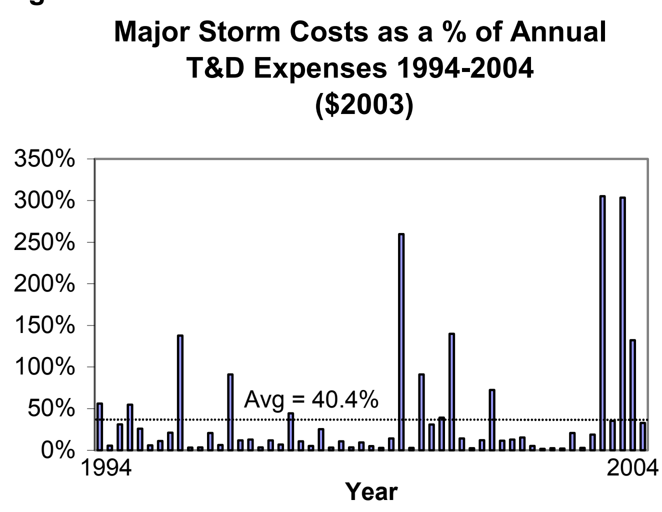


Figure 8 provides another way of gauging the potential impact of major storms by comparing the storm's costs to what the utility spends each year to operate and maintain its entire transmission and distribution system. The data provides another indication of the significant financial impact a storm can have on a utility's financial condition. For those companies hit by a major storm between 1994 and 2004, the costs averaged 40 percent of what the company spent during the year to operate and maintain its entire transmission and distribution system. Several storms exceeded company expenditures for T&D for the year.

Figure 8



The data depicted in these charts does not present a true picture, however, of the actual financial impact of a major storm on a utility. Many regulatory commissions allow accounting policies and special rate treatments that minimize the potentially significant financial costs that storms can inflict. Greater insight into these policies and practices and how they are deployed in the industry is provided in the next section of the report.

PAYING FOR MAJOR STORM RESTORATION

Special accounting and regulatory treatments for storm costs can play a major role in helping utilities recover from the financial impact of a major storm.

Even with the $1.4 billion price tag that the major Florida utilities were faced with for restoring their systems after the 2004 hurricanes (*Figure 9*), Wall Street did not feel compelled to change the credit ratings of any of the major Florida utilities. In deciding to maintain its current ratings, Standard and Poor's cited "storm damage reserves maintained by the utilities, the ability to recover storm-related expenses through rates, a favorable regulatory history with such recovery, and sound liquidity."[4]

However, Standard & Poor's did change its outlook for Progress Energy from stable to negative because of concerns that costs associated with the 2004 hurricanes would delay the company's progress in paying down its high debt levels. Moody's also put the company's ratings under review for possible downgrade, citing the timing of the recovery of storm costs as one of their concerns.

Figure 9
Cost of 2004 Hurricanes for Florida Investor Owned Utilities

	Storm Cost $Million
Florida Power & Light	$ 890
Progress Energy Florida	$ 366
Tampa Electric	$ 60
Gulf Power	$ 109
Total Storm Cost	$ 1,425

Source: Company reports

Accounting for Normal vs. Major Storms

Almost all utilities distinguish between "normal" storms and "major" storms. While there is an IEEE standard definition of a major storm, it is relatively new and not widely used. The general criteria for classifying a storm as "major" depends on whether the storm has a significant impact on a company's customers, i.e. a substantial number of customers are without power for a significant period of time. Baltimore Gas and Electric, for example, defines a major storm as one in which 10 percent of its customers are without power for a day or more. Public Service of New Hampshire defines a major storm as one that results in either (a) 10 percent or more of its customers losing power, resulting in 200 or more reported troubles, or (b) 300 or more reported troubles.[5] Storms that are not classified as major fall under normal accounting rules. Major storms, however, often receive special accounting treatment.

Distinguishing Between Storm Capital and O&M Costs

Major storm expenses are separated into capital and operations and maintenance (O&M) components. Storm capital costs, such as pole and transformer replacements, are treated similarly throughout the industry. They are capitalized on a company's books as a depreciable asset and in most cases are eligible for inclusion in a utility's rate base. Once these costs are included in the rate base, the utility can recover the capital portion of major storm costs from its rate payers.

[4] "Storms Likely to Have Little Effect on U.S. Utility Credit", Sept. 21, 2004, Jodi E. Hecht, Standard & Poor's, New York, New York.
[5] Information provided in company interviews.

In few instances, companies incurring extraordinary storm costs have been allowed to defer capital storm costs and recover them through a special customer surcharge.[6]

While the ratio of capital to O&M costs can vary significantly from storm to storm, a general rule of thumb appears to be that the capital component of a major storm's costs is approximately 20-25 percent of total storm costs.

Recovery of major storm-related O&M costs is different from capital costs. For many companies, expensing major storm costs in the period in which they occur could result in a huge financial burden that could jeopardize the financial standing of the company. The reaction on Wall Street, for example, would have likely been much different if the Florida utilities had been required to expense the O&M component of the 2004 hurricane costs in 2004. Even the possibility of having to incur such a charge could significantly change the level of risk that bondholders and stockholders perceive for a company and increase its overall financing costs.

Storm Insurance

Until Hurricane Andrew in 1992, commercial insurance was widely available at affordable rates to protect against catastrophic storms. FPL, for example had a transmission and distribution system policy with a limit of $350 million per occurrence. The 1992 premium for this policy was $3.5 million. After Hurricane Andrew, commercial insurance carriers stopped writing such policies altogether or made them so expensive that they could not be justified. For example, the quote FPL received in 1993, the year after Hurricane Andrew, was for $23 million for a transmission and distribution system policy with an aggregate annual loss of $100 million.

In lieu of paying for expensive storm insurance, FPL elected to self-insure. It currently funds its storm reserve account at a level of about $20 million a year. This amounts to about 20 cents per month for a typical residential customer.

To help minimize the potential financial consequences of major storms, some utility regulators have allowed their utilities to employ different types of accounting treatments for major storm O&M costs. Generally, major storm O&M expenses that are not expensed receive one of two types of accounting treatments:[7]

1. They are charged to a special storm reserve account, or
2. They are deferred and paid back over an extended period of time.

Each of these accounting treatments is described in more detail on the next page.

[6] Both FPL and Progress Energy Florida have requested that they be allowed to recover their incremental capital costs as well as O&M costs associated with the 2004 hurricanes through a special customer surcharge. In the past, the Florida Public Service Commission allowed capital costs associated with Hurricane Andrew to be recovered through storm reserve accounts.

[7] Co-ops and municipal utilities are an exception. They are eligible to recover 75 percent of their storm costs through FEMA

Utility Storm Reserves

A large number of investor-owned utilities were surveyed to determine how they were accounting and paying for major storm costs. Of the 28 companies contacted, approximately 12, or slightly less than half, indicated that their commissions allowed them to establish special storm reserves (*Figure 10*).

What are these reserves and how do they work?

A storm reserve is an accounting technique that allows utilities to smooth out the earnings impact of major storms. With the exception of FPL, storm reserves are not funded with cash and therefore do not minimize the cash-flow impact of having to pay the costs of a major storm.

When a utility establishes a storm reserve, it credits a fixed amount each year to the reserve through monthly accruals.[8] These monthly accruals are deducted from the current month's earnings even though no actual storm costs are incurred. When a major storm strikes, the storm costs are charged against the balance in the storm reserve account. The reserve, however, provides no cash to pay the actual storm costs.[9]

The big benefit of this type of accounting treatment is that it allows utilities to smooth out the earnings impact of major storms. When a big storm strikes, the only charge to earnings the utility incurs is its normal monthly accrual to its storm reserve account, assuming that it has a balance in its storm reserve account.

Figure 10
Companies with Storm Reserves

Company	Storm Reserve?[1]
Alabama Power	Yes
Avista	No
Baltimore Gas & Electric	No
Black Hills	No
Central Hudson	No
Central Maine Power	No
Cleco	Yes
Connecticut Light & Power	Yes
Duke Power Company	No
Entergy Arkansas	Yes
Florida Power & Light	Yes
Georgia Power	Yes
Gulf Power	Yes
Mississippi Power	Yes
Progress Energy Florida	Yes
Public Service New Hampshire	Yes
Puget Sound Energy	No
Rochester Gas & Electric	Yes
Sierra Pacific	No
Tampa Electric	Yes
Westar	Yes
Western Mass Electric	No
Conectiv	No
Progress Energy Carolinas	No
Dominion	No
Nevada Power	No
Kansas City Power & Light	No
Duquesne Power & Light	No

[1] Note: Many companies have the opportunity to petition their commissions for deferrals of "significant" storm costs, but do not have a formal policy in place to establish a reserve or deferral. Only those companies with established policies for storm reserves are identified in this column.

With the 2004 hurricanes, FPL, Progress Energy Florida, Tampa Electric and Gulf Power all incurred storm related O&M costs that exceeded the balance in their storm reserve accounts. (*See Figure 11, page 12.*) To avoid charging these non-accrued amounts against current earnings, the Florida Public Service Commission allowed each of the Florida utilities to account for the excess as a negative balance in the companies' storm reserve accounts. The Florida Commission indicated that it viewed the negative balance in the storm reserve account as a temporary solution until "an alternative accounting treatment for recovery of prudently incurred

[8] Most companies appear to accrue less than $5 million year. The highest accrual identified was $20 million per year for FPL.

[9] Even with the magnitude of the storm costs that FPL and Progress Energy incurred, rating agencies did not see these costs as a serious threat to overall liquidity; in other words, both companies had sufficient access to commercial paper and bank lines to pay the cash costs of the storms.

storm damage costs…" could be established.[10] This treatment allowed all three companies to avoid taking a charge to earnings in 2004 and helped the companies maintain their credit ratings.[11]

Figure 11
2004 Hurricane Costs vs. Reserve Balances

	Total Storm Cost ($Million)	Reserve Balance Before Storms ($Million)
FPL	$ 890.0	$ 345.0
Progress Energy Florida	$ 366.0	$ 45.4
Tampa Electric	$ 60.0	$ 42.7
Gulf Power	$ 109.0	$ 28.0

Had these reserve funds not been in place and had the Florida Commission not signaled that it was willing to work with the Florida companies to work out a plan for recovering prudently incurred storm costs carried as negative balances in storm-reserve accounts, it is likely that the companies would have suffered a much greater financial impact, which could have jeopardized their ratings and increased their financing costs.

Special Deferrals of Storm Costs

Another accounting technique used to minimize the financial impact of major storms is to defer all or a portion of the storm-related O&M costs. Unlike credits to storm reserve accounts, deferrals typically are not routine events and typically require the utility to ask its commission for special accounting treatment after a major storm causes a significant financial impact on the utility.

When a deferral is established, all or a portion of the storm-related O&M costs are amortized over an extended time period, usually two to three years. The rationale for establishing the deferral is to smooth out the earnings impact of the storm.

Storm costs that are deferred may or may not be recoverable from rate payers. In many instances, the deferred costs are paid for through a special surcharge assessed on each customer's bill until the storm reserve is paid off. Some utilities, however, are expected to pay off the deferred storm costs out of their earnings.

[10] Florida Public Service Commission order in Docket No. 041057-EI, Sept. 21, 2004.

[11] In November 2004, both FPL and Progress Energy requested permission from the Florida Public Service Commission to amortize the negative balances they were carrying in their storm reserve accounts over a two-year period. The amortization would result in a surcharge beginning in January 2005 of $2.09 per month for FPL customers and $3.81 per month for Florida Progress customers.

Figure 12
Examples of Deferred Treatment for Storm Costs

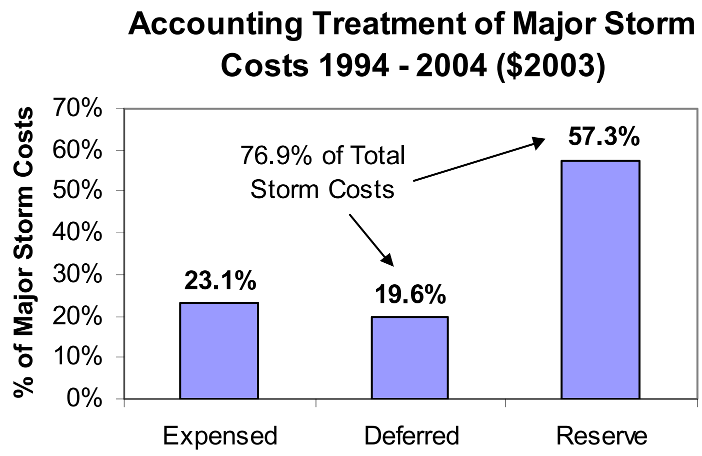
Company	Storm Cost Treatment
Central Maine Power	Total costs for 1998 ice storm were $56 million. FEMA reimbursed $20 million through the state, and $34 million O&M balance was deferred over three years.
Progress Energy Carolina	Usually expenses the first $10 million of O&M costs for large storms. Defers remainder of O&M costs for three years with utility commission approval.
Central Hudson	Deferred expenses for large snowstrom in 1997 and for Hurricane Floyd in 1999.
Kansas City Power & Light	Amortized expenses for 2002 ice storm over five years
Sierra Pacific	O&M portion of 2002 snowstorm ammortized over 4 years
Puget Sound Enegy	Deferred expenses for wind storms in 1996, 1999 and 2003
Conectiv and BG&E	In Maryland, Conectiv and BG&E are allowed to include a historical average of their previous storm costs in the test year costs they use for determining future revenue requirements.

Figure 12 summarizes the deferral accounting treatment some companies have received that allows them to defer their storm costs. Included in the table, even though it is not technically a deferral, is a summary of the special accounting treatment that Conectiv and BG&E receive from the Maryland Public Service Commission that allows them to include an average of historical storm costs in the test year they use for rate cases.

This accounting treatment essentially allows these companies to pre-pay at least a portion of their storm costs by collecting revenues from their customers to pay for storms that have not yet occurred. One shortcoming of this technique is that it does little to smooth out the earnings impact of severe storms such has Hurricane Isabel, which struck in 2003 and required both companies to incur significant charges to earnings in 2003.

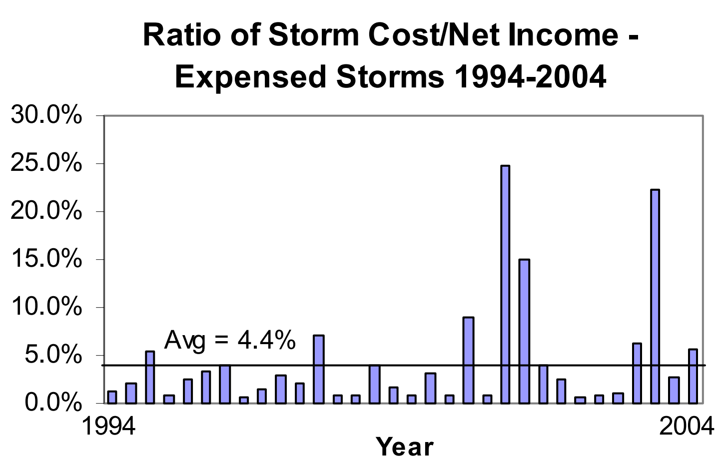
Based on the survey results presented in Figure 2, it appears that substantial portions of storm costs were recovered through existing storm reserves or were eligible for deferred accounting treatment. The data on storm cost accounting treatment is summarized in Figure 13 and indicates that almost 75 percent of total storm costs were covered by some type of storm reserve or deferred accounting treatment. *(See page 14.)* This significantly reduces the financial impact of the storm.

Figure 13



The remaining storms' costs are expensed. While the costs of these expensed storms were significant, they appear "manageable." Figure 14 compares the ratio of storm costs obtained from the survey to net operating income. On average the major storm costs that were expensed equaled 4.4 percent of net operating income. This is about a third of what the average would have been if the storm costs eligible for storm reserve and deferred accounting treatment had been included. (*See Figure 7, page 8.*) Equally significant, only a handful of the expensed storms were significantly above the 4.4 percent average.

Figure 14



There are no assurances, however, that utilities will continue to receive the favorable regulatory treatment for recovery of storm costs that they received in the past. The whole issue of storm cost recovery appears to be becoming more politicized in the current environment. For example, on Nov. 17, 2004, the Florida Office of Public Counsel and the Florida Industrial Power Users Group filed motions with the Florida Public Service Commission requesting that it deny FPL's and Progress Energy Florida's petitions to establish special customer surcharges to pay for hurricane costs.

CONCLUSION & RECOMMENDATIONS

Storms are expensive. The EEI survey identified 81 storms between 1994 and 2004 that caused approximately $2.7 billion ($2003) in damage to electric utility systems. While this is a big number, it is only a fraction of the regional economic losses resulting from being without power in the aftermath of a large storm. With this kind of societal impact, it is clearly in everyone's best interest to restore power as quickly as possible.

Because of the high costs utilities incur in their storm restoration efforts, there is a potential for large financial losses for individual utilities. For more than 75 percent of the major storm costs identified in the survey, the financial impacts were mitigated through storm reserves or deferral of storm costs. For the 25 percent of storm costs that were written off, the financial impact, with a few exceptions, did not appear to present a major financial hardship.

Of concern, however, is the uncertainty that surrounds storm cost recovery and the degree to which storm recovery is becoming politicized. The industry knows that large storms will occur and it knows that the financial consequences of these storms could be significant and in some cases catastrophic. Despite this, recovery of costs for most major storms is dealt with after the fact. This makes it difficult for utility managers to plan and creates uncertainty on Wall Street.

What is ironic, given the importance of storm restoration, is that more established and consistent policies regarding storm cost recovery are not in place. From a cost recovery standpoint, why is recovery of storm restoration costs any different than recovery of insurance premiums? Both represent a cost item for operating a modern utility. Yet, the industry has vastly different philosophies regarding cost recovery of these two items.

Given the lack of commercially available storm insurance at affordable rates, the industry should adopt a self-insurance mechanism for storms, either within individual companies or possibly on an industry basis. Looking at the establishment of a storm reserve with regulatory approvals for monthly reserve accruals or possibly even cash deposits is a good starting point.

The storm reserve funds identified in this report do what they were intended to do—minimize the financial impact of major storms at an affordable cost ($.20/month for a typical FPL residential customer). With Wall Street starting to focus on this issue, consideration must be given to establishing reserves as a type of "rainy day fund" for when it becomes necessary to offset the serious economic impact of future storm restoration.

ATTACHMENT A: SAMPLE SURVEY

EEI Major Storm Restoration Cost Survey

EEI is seeking member company support in obtaining historical data that can be used to quantify the financial impact of major storms on utilities and their customers (e.g. Hurricane Isabel, 2002 North Carolina ice storm).

Please complete the following survey form for the 10 most severe storms your company has experienced since 1994. Use peak number of customers out of service to rank storm severity. Please provide all storm data at the operating company level, not the holding company level.
Holding companies should complete a separate survey form for each operating company they are providing storm data for.

Completed surveys should be e-mailed to William Mayer at wmayer@eei.org by ***November 5, 2004***.
All questions should be addressed to William Mayer at 202-508-5563

Note: All specific company data will remain confidential. No company names will be released in any storm-data reports.

Operating company name: ______________________

Name of individual completing survey: ______________________
Individual contact information:
Phone number: ______________
E-mail address: ______________

MAJOR STORM RESTORATION COST DATA

		STORM IMPACT					STORM COST
				CAIDI Data			
Major Storm Event	Date	Outage Duration (Days)	Peak # Customers Out	Sum of Customer Outage Durations (Hours)	Total Customers Interrupted During Storm	MWhrs of load not served (MWhrs)	Restoration Cost (Storm Yr $)
Hurricane 1 (Sample Data)	Oct-97	6	310,000	22,500,000	450,000	648,000	$ 42,000,000

METHOD OF RECOVERING STORM COSTS

Major Storm Event	Method of Cost Recovery (expensed, reserve account, deferral account, other)	Brief summary of any special actions taken with respect to recovering storm costs
Hurricane 1	Expensed	Commission did not allow deferral of storm costs

Survey Instructions

Please complete the attached storm restoration survey form. All data should be provided at the operating company level. For holding companies, separate survey forms should be completed for each operating company for which storm data is being provided.

Major Storm Event:
A major storm event is defined as a storm resulting in a multi-day outage for a significant percentage of total customers. Please indicate the type of storm, e.g. hurricane, ice storm, snowstorm, or wind and lightning storm in your response.

Date:
Please indicate the month and year storm restoration work was completed.

Outage Duration:
Number of days to restore system following the storm.

Peak Number of Customers Out:
The largest number of customers simultaneously without power during the storm event.

Total Duration of Customer Interruptions:
The duration of customer outages is calculated by adding the customer-hours of interruptions experienced during the storm period. For example, if 200 customers were out of power for 30 hours and 500 customers were out of power for 20 hours, the duration of customer outages would be (200 x 30) + (500 x 20) = 16,000 customer hours. (Calculate in the same manner as the duration of customer interruptions is calculated for the CAIDI Index).

Total Customers Interrupted:
The total number of customers without power at some point during the storm event. Note: some customers may experience multiple outages during a storm event. These outages should be treated as separate outage incidents attributed to the storm. (Calculate in the same manner as the total number of customers is calculated for the CAIDI Index).

MWhrs of Load Not Served:
The estimate of the difference between the MWhr sales to ultimate customers that actually occurred during the storm restoration period and the sales that would have occurred if the storm had not happened.

Restoration Cost:
The estimate of the total direct costs incurred to provide storm restoration. Costs should be reported in storm year dollars, i.e. no escalation for inflation.

Accounting Treatment of Storm Costs:
Briefly describe how storm costs are accounted for, i.e. expensed against current year earnings, charged to a special reserve account set up to pay for storm costs, deferred through a special reserve account or any other accounting treatments that have been used for storm related costs. Briefly describe any special actions taken with respect to recovering storm costs such as requesting a rate increase to recover storm related costs.

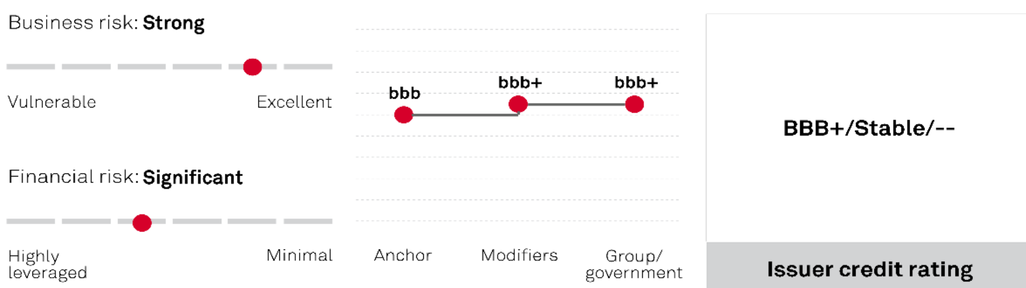
EDISON ELECTRIC INSTITUTE

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
202-508-5000
www.eei.org

Maritime Electric Co. Ltd.

July 10, 2023

Ratings Score Snapshot



Primary contact

Mayur Deval
Toronto
1-416-507-3271
mayur.deval
@spglobal.com

Secondary contact

Matthew L O'Neill
New York
1-212-438-4295
matthew.oneill
@spglobal.com

Research contributor

Piyush Seth
CRISIL Global Analytical Center, an S&P Global Ratings affiliate
Pune

Credit Highlights

Overview

Key strengths	Key risks
Low-risk, integrated electricity generation, transmission, and distribution utility.	Lacks geographic and regulatory diversity, operating only in the province of Prince Edward Island (PEI).
Generally supportive regulatory framework that minimizes the utility's exposure to commodity input costs.	Risk of political interference in establishing energy policy and setting rates from provincial government.
A moderately strategic entity to its parent Fortis Inc., which we expect would provide extraordinary support under some circumstances.	

The utility is exposed to potential political interference through the provincial government, which 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.

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, while we rate Maritime Electric Co. Ltd.'s (MECL) business risk profile as strong, we consider its business risk to be higher than those of its utility peers. We ascribe a positive comparable rating analysis modifier to reflect this.

Outlook

The stable outlook reflects our expectations that the company will maintain a constructive relationship with its regulator, continue to harden its electric system over time, and generate stable and predictable financial measures. Over the next two years, we expect MECL's stand-alone funder from operations (FFO) to debt in the 16%-19% range.

Downside scenario

We could downgrade MECL over the next 12 months if:

- MECL experiences adverse regulatory rulings, severe storms, volatile profit measures, or operational setbacks that result in a higher business risk; or
- Its financial measures weaken, including FFO to debt of consistently below 16%.

Upside scenario

We could raise our ratings on MECL over a similar period if its financial measures improve, including FFO to debt consistently above 25%, without a weakening of business risk profile.

Our Base-Case Scenario

Assumptions

- The economy in its service territory remains stable with a modest increase in its customer base;
- No material adverse regulatory decisions;
- Capital expenditure (capex) averaging about C$90 million per year through 2025; and
- Average annual dividends of C$2 million through 2025.

Key metrics

Company Description

MECL is an integrated electricity generation, transmission, and distribution utility with operations throughout PEI. It provides services to more than 87,800 customers and is regulated by Island Regulatory and Appeals Commission (IRAC). MECL is an indirect wholly owned subsidiary of Fortis Inc.

Business Risk

Our assessment of MECL's business risk reflects 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.

We view the island as increasing susceptibility to physical risks due to climate change, even though the company is planning on hardening many portions of its system. Over many years, MECL proactively invested in the hardening and replacement of portions of its electric system to minimize customer service outages. Despite these improvements, the region remains susceptible to physical risks from the increasing prevalence of storm systems, winter ice, and sleet activity in the region. Also affecting the company's business risk profile is its very small customer base (only about 87,800) and its lack of geographic diversity (its service territory is limited to a single island). If the company experiences a severe storm, it will likely affect its entire service territory and recovering such costs would likely be more challenging than for most larger and more diversified utilities.

Our assessment of MECL's business risk also reflects the active role that the IRAC and the provincial government of PEI 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 a track record of credit-supportive policies. As such, we expect the company to maintain constructive relationships with its regulator in a manner that continues to support its credit quality.

We believe the storm risk for MECL marginally increases as the pace of climate change intensifies. We also believe MECL's business risk profile is now more in line with its other island peers such as Caribbean Utilities Co. and Hawaiian Electric Co. Inc.

Additionally, we believe MECL has somewhat higher emission risks because the utility relies on diesel as its primary fuel for its on-island back-up generators. Overall, MECL purchases most of its power supply, about 75%, from neighboring province New Brunswick, including about 15% from the Point LePreau nuclear generation station, and 25% from on-island wind assets.

Offsetting much of the aforementioned risks is our assessment of MECL as a monopolistic lower-risk, rate-regulated vertically integrated electric utility that has a track record of constructive regulatory outcomes and stable profit measures. MECL has generally managed regulatory risk effectively by relying on credit-supportive mechanisms such as energy cost adjustments and weather normalization in its rates, which provide stable cash flows, minimizing profit volatility. Overall, we assess the company at the higher-end of range for its assessed category of its business risk profile. To account for this, we assess the comparable rating analysis modifier as positive.

Financial Risk

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 rate decision from the IRAC in April 2023 that Includes a rate increase of about 2.6% effective May 1, 2023. The rate settlement also includes revenue increase of about 2.6% and 2.7% effective March 1, 2024, and March 1, 2025, respectively. The rates are based on an approved ROE of 9.35% with an upper band of 9.70%. This means that although an ROE of 9.35 was used to calculate customer rates, MECL will have the opportunity to earn an ROE of up to 9.7 percent through operating efficiencies or business growth.

Under our base-case assumptions that include the most recent rate case outcomes, capital spending averaging about C$90 million through 2025, and dividends of about C$2 million per year, we forecast the company will maintain FFO to debt of about 16%-17% during our two-year outlook period.

Liquidity

We assess MECL's liquidity as adequate because we believe its liquidity sources will likely cover uses by more than 1.1x over the next 12 months and meet cash outflow even if EBITDA declines 10%. The assessment also reflects our view of the company's generally prudent risk management, sound relationship with banks, and generally satisfactory standing in the credit markets. We believe the predictable regulatory framework for MECL provides manageable cash flow stability even in economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, we believe MECL can absorb high-impact, low-probability events given that it maintains about C$90 million in committed credit facilities, and we believe it can lower its high spending (averaging about C$92 million annually) during stressful periods, indicative of a limited need for refinancing under such conditions. Overall, we believe the company can withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has no significant long-term debt maturities for the next five years.

Principal liquidity sources

- Available committed credit facilities of about C$33.3 million as of Dec. 31, 2022; and
- Cash FFO of about C$50 million over the next 12 months.

Principal liquidity uses

- Capex of C$53 million over the next 12 months; and
- Dividend payments of about C$2 million over the next 12 months.

Environmental, Social, And Governance

ESG Credit Indicators

E-1	**E-2**	E-3	E-4	E-5	S-1	**S-2**	S-3	S-4	S-5	G-1	**G-2**	G-3	G-4	G-5

ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1-5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicator Definitions And Applications," published Oct. 13, 2021.

ESG factors have no material influence on our credit rating analysis of Maritime Electric Co. Ltd. That said, potential waste, health, and safety risks are relevant given the company's indirect exposure to nuclear power generation.

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, 2022, MECL's capital structure comprised about C$56.4 million of short-term borrowings and C$260 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).

Rating Component Scores

Foreign currency issuer credit rating	BBB+/Stable/--
Local currency issuer credit rating	**BBB+/Stable/--**
Business risk	**Strong**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Satisfactory
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**bbb**
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	Positive (+1 notch)
Stand-alone credit profile	**bbb+**

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, 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
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, 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

Ratings Detail (as of July 10, 2023)*

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/--
Related Entities	
Caribbean Utilities Co. Ltd.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Central Hudson Gas & Electric Corp.	
Issuer Credit Rating	BBB+/Stable/NR
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

Ratings Detail (as of July 10, 2023)*

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.

Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Depreciation (000s)	**Reference**		**Annual**
Depreciation Expense			
Capital Investment - Fiona Restoration	A		14,756
Retirements	B		(1,281)
Plant Investment for Depreciation	C = A + B	$	13,475
Depreciation Rate (Note 1)	D		3.76%
Year 1 Depreciation Expense - first full year of depreciation	E = C X D	$	507
Capital Investment			
Capital Investment	A		14,756
Less: Customer Contributions (assumed to be nil)	F		-
Total Capital Investment	G = A + F	$	14,756
Accumulated Depreciation			
Costs of Removal (Note 3)	H		(4,523)
Accumulated Depreciation, Year 1	E		507
Total Change in Accumulated Depreciation	I = H + E	$	(4,016)
Net Book Value (NBV) - Plant Investment	**J = C - I**	**$**	**17,490**
Customer Contributions			
Customer Contributions	F	**$**	**-**
Depreciation Expense - Contributions			
Annual Contributions	F	$	-
Depreciation Rate	K		0.00%
Amortization of Customer Contributions	L = F X K	$	-
Net Book Value (NBV) - Customer Contributions	**M = F - L**	**$**	**-**
Total 2024 Depreciation Expense (Net of Contributions)	**N = E + L**	**$**	**507**

Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Deferral Amortization (000s)	**Reference**		**Annual**
Operating Costs and Carrying ChargesDeferred	A	$	17,662
Amortization Rate (5 Year)	B		20.00%
Year 1 Amortization	C = A x B	$	3,532
Capital Investment			
Capital Investment	A		17,662
Less: Customer Contributions Assumed to be Nil	D		-
Total Capital Investment	E = A + D	$	17,662
Accumulated Depreciation			
Accumulated Amortiziation, Year 1	F		3,532
Net Book Value (NBV) - Regulatory Deferral	**G = E - F**	**$**	**14,129**
Customer Contributions			
Customer Contributions	D	**$**	**-**
Depreciation Expense - Contributions			
Annual Contributions	D	$	-
Depreciation Rate	H		0.00%
Amortization of Customer Contributions	I = D X H	$	-
Net Book Value (NBV) - Customer Contributions	**J = D - I**	**$**	**-**
Total Year 1 Amortization Expense (Net of Contributions)	**K = C + I**	**$**	**3,532**

Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Income Taxes (000s)	**Reference**		**Annual**
Capital Cost Allowance			
Capital Investment - Fiona Restoration	A = C from Page 1		13,475
Capital Cost Allowance ("CCA") Rate - Assumes Class 47	B		8%
CCA Deductions Year 1	C = A x B x 150%		1,617
Ending UCC	D = A - C	$	11,858
Future Income Taxes			
CCA Deductions Year 1	C	$	1,617
Accumulated Depreciation, Year 1	E = - N from Page 1		(507)
Cost of Removal deducted immediately for tax	F		4,523
Difference CCA/Depreciation and Cost of Removal	G = C - E + F		5,633
Future Tax Rate	H		31.00%
Future Income Tax Liability	I = G X H		1,746
Income Tax Effects of Increased Return			
Return on Rate Base	J = H from Page 4	$	1,998
Tax Gross Up on Equity Return	K = G from Page 4 / (1-H) * H		509
Debt Return	L = F from Page 4		(865)
	M = J + K + L	$	1,642
Income Tax Expense			
Return on Rate Base	M	$	1,642
Add: Depreciation	N = N from Page 1		507
Less: CCA	O = C		(1,617)
Taxable Income	P = M + N + O		532
Corporate Tax Rate	Q		31.00%
Current Income Tax Expense	R = P X Q		165
Future Income Tax Expense	S = (N + O) X Q		344
Total Income Tax Expense	**T = R + S**	**$**	**509**

Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Rate Base & Cost of Capital (000s)	**Reference**		**Annual**
Net Book Value, Capital Investment	A = J from Page 1	$	17,490
Net Book Value, Regulatory Deferral	B = G from Page 2		14,129
Future Income Tax Liability	C = I from Page 3		(1,746)
Projected Rate Base	**D = A + B + C**	**$**	**29,873**
Total % Increase from 2024 Forecast Year End Rate Base	**E = D / R**		**5.95%**
Return on Debt	F = D X O	$	865
Return on Common Equity	G = D X P		1,133
Total Return On Rate Base	H = F + G	$	1,998
Weighted Average Cost of Capital ("WACC")			
Debt	I		60.0%
Common Equity	J		40.0%
Cost of Debt	K		4.77%
Cost of Common Equity	L		9.35%
Forecast 2024 Average Capitalization (Total Debt plus Common Equity)	M		498,120,300
Forecast 2024 Average Rate Base*	N		491,764,300
WA Cost of Debt	O = I X K X M/ N		2.90%
WA Cost of Common Equity	P = J X L X M/ N		3.79%
Forecast 2024 WACC	Q = O + P		6.69%
Forecast 2024 Year End Rate Base *	**R**	**$**	**502,100**

* Per Negotiated Settlement Agreement.

Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Annual Project Revenue Requirement (000s)	Reference		Annual
Depreciation	A = N from Page 1	$	507
Amortization of Regulatory Deferral	B = N from Page 2	$	3,532
Return on Debt	C = F from Page 4	$	865
Return on Equity	D = G from Page 4	$	1,133
Income Taxes	E = T from Page 3	$	509
Estimated Annual Project Revenue Requirement	**F = A + B + C + D + E**	**$**	**6,547**
% Increase Forecast Annual Revenue Requirement	**G = F / H**		**2.5%**
Forecast 2024 Revenue Requirement*	**H**	**$**	**260,578**

Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Negotiated Settlement Rates
Composition of Total Energy Charge per kWh by Rate Class
Effective March 1, 2024 & 2025

Energy Charge per kWh - Revenue Requirement (A)	2024	2025	Proposed Fiona Adjustment: Adjustment for Fiona Recovery	Revised 2024F	Revised 2025F
Residential - First Block	$ 0.1602	$ 0.1663	$ 0.0049	$ 0.1651	$ 0.1712
Residential - Second Block	$ 0.1267	$ 0.1315	$ 0.0039	$ 0.1306	$ 0.1354
General Service - First Block	$ 0.1978	$ 0.2053	$ 0.0061	$ 0.2039	$ 0.2114
General Service - Second Block	$ 0.1281	$ 0.1329	$ 0.0039	$ 0.1320	$ 0.1368
Small Industrial - First Block	$ 0.1936	$ 0.2009	$ 0.0059	$ 0.1995	$ 0.2068
Small Industrial - Second Block	$ 0.0959	$ 0.0995	$ 0.0030	$ 0.0989	$ 0.1025
Large Industrial	$ 0.0797	$ 0.0830	$ 0.0024	$ 0.0821	$ 0.0854

Energy Charges per kWh - Other Amounts (B)	2024	2025	Revised 2024F	Revised 2025F
ECAM Charge per kWh	$ 0.0029	$ 0.0015	$ 0.0029	$ 0.0015
October 1, 2023 ECAM Adjustment			$ 0.0033	$ 0.0033
Subtotal - Total ECAM Charge per kWh	$ 0.0029	$ 0.0015	**$ 0.0062**	**$ 0.0048**
Provincial Energy Efficiency Program per kWh	$ 0.0003	$ 0.0012	$ 0.0003	$ 0.0012
Total Energy Charge per kWh Excluding Basic Revenue	**$ 0.0032**	**$ 0.0027**	**$ 0.0065**	**$ 0.0060**

Total Energy Charge per kWh (A+B) - Option - Negotiated Settlement Agreement	2024	2025	Revised 2024F	Revised 2025F
Residential - First Block	$ 0.1634	$ 0.1690	$ 0.1716	$ 0.1772
Residential - Second Block	$ 0.1299	$ 0.1342	$ 0.1371	$ 0.1414
General Service - First Block	$ 0.2010	$ 0.2080	$ 0.2104	$ 0.2174
General Service - Second Block	$ 0.1313	$ 0.1356	$ 0.1385	$ 0.1428
Small Industrial - First Block	$ 0.1968	$ 0.2036	$ 0.2060	$ 0.2128
Small Industrial - Second Block	$ 0.0991	$ 0.1022	$ 0.1054	$ 0.1085
Large Industrial	$ 0.0829	$ 0.0857	$ 0.0886	$ 0.0914

* Rate changes effective March 1.

Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Customer Impact	**Reference**	**Annual**
Forecast Increase Annual Cost Benchmark Residential Customer (650 kWh per month) before tax	**A = 650 kWh X Fiona Rate Change X 12 months**	**$ 38.22**
% Increase over 2024 Forecast Annual Cost for Rural Residential Customer	B = A / F	2.4%
% Increase over 2024 Forecast Annual Cost for Urban Residential Customer	C = A / G	2.4%
Forecast Increase Annual Cost Benchmark General Service Customer (10,000 kWh per month) before tax	**D = 10,000 kWh X Fiona Rate Changes X 12 months**	**$ 600.00**
% Increase over 2024 Forecast Annual Cost for General Service Customer	E = D / H	2.4%
2024 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per Negotiated Settlement Agreement.	F	$ 1,596.25
2024 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per Negotiated Settlement Agreement.	G	$ 1,568.05
2024 Annual Cost Benchmark General Service Customer (10,000 kWh per month) excluding tax per Negotiated Settlement Agreement	H	$ 25,046.84