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TECO’s Response to OPC's Second Production of Documents Nos. 4-7

(Nos. 4-5, and 7 have attachments)

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4. Please provide all documents demonstrating how you considered the customer rate impacts of the programs and projects included in your pending SPP.

A. Tampa Electric is providing the documents that were used to calculate the projected rate impacts for the first three-years of the SPP. Rate impacts are not considered for individual SPP Programs or SPP Projects. The following three Excel files are included:

- (BS_2) Final Year 2022 rate impact
- (BS_3) Final Year 2023 rate impact
- (BS_4) Final Year 2024 rate impact

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5. Please provide all documents that demonstrate or show that the company has considered or determined an upper limit to the amount of capital expenditures that could be placed upon customers through the SPP and the SPPCRC.

A. As explained in Response No. 50 of Citizens Second Set of Interrogatories to Tampa Electric Company, the company has not considered or determined an upper limit of capital expenditures that could be placed upon customers through the SPP and the SPPCRC. Tampa Electric is providing the Storm Protection Plan ("SPP") Studies that were performed by 1898 & Co. for the company's initial 2020-2029 SPP and the 2022-2031 SPP in this proceeding. In these studies, the company and 1898 & Co. performed a resilience benefit analysis that considered several alternatives to include the Status Quo and various hardening investment levels.

In the 2020-2029 SPP Study, this resilience analysis examined investment levels from $250 million over 10 years to $2.5 billion over 10 years. The scenario results for the Budget Optimization were shown on the following figures within the 2020-2029 SPP Study:

- Figure 1-2
- Figure 6-1

The figure includes the P50, P75, and P95 results from their respective 'S-Curves'. This figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2020 dollars for the Tampa Electric Storm Protection Plan. In this initial study, the overall investment level is right before the point of diminishing returns showing that the company's initial 2020-2029 SPP plan has an appropriate level of investment capturing the hardening projects that provide the most value to customers.

In the company's 2022-2031 SPP, this same resilience analysis was performed with same investment levels investment levels over the ten-year SPP horizon. The scenario results for the Budget Optimization were shown on the following figures within the 2022-2031 SPP Study:

- Figure 1-2
- Figure 6-1

The figure includes the P50, P75, and P95 results from their respective 'S-Curves'. This figure shows significantly increasing levels of net benefit from the $250 million to $1.25 billion with the benefit level flattening from $1.25 billion to $1.75 billion and decreasing from $1.75 billion to $2.5 billion. The figure also shows the total investment level in 2021 dollars for the Tampa Electric Storm Protection Plan. The company's 2022-2031 SPP overall investment level is right before the point of diminishing returns, which demonstrates that Tampa Electric's plan has an appropriate level of investment over the next 10 years, again, capturing the hardening projects that provide the most value to customers

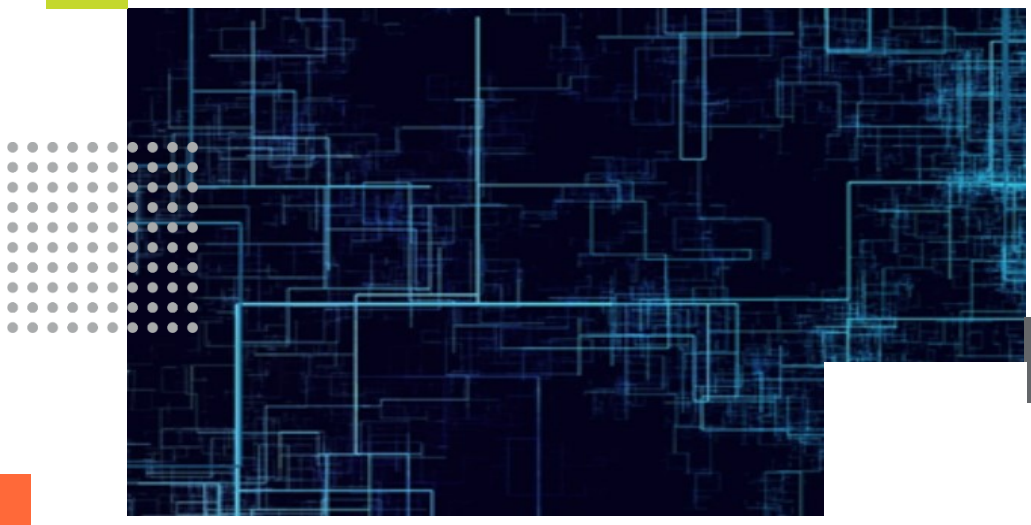
This resilience-based planning approach is a customer centric evaluation that focuses on storm scenarios and ranges of investment levels for system hardening. This methodology does not find an upper limit or theoretical maximum amount the company could invest or determine what amount could be placed upon customers through the SPP and the SPPCRC.

Storm Protection Plan Resilience Benefits Report

Tampa Electric Company

TEC SPP Resilience Benefits Report
Project No. 121429

Revision 0
4/10/2020



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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
AHI	Asset Health Index
ANL	Argonne National Laboratory
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CMI	Customer Minutes Interrupted
DOE	Department of Energy
FLISR	Fault Location, Isolation, Service Restoration
GIS	Geographic Information System
ICE	Interruption Cost Estimator
IEEE	Institute of Electrical and Electronics Engineers
LOF	Likelihood of Failure
MED	Major Event Day
NARCU	National Association of Regulatory Utility Commissioners
NASC	National Electric Safety Code
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
OMS	Outage Management System
PNNL	Pacific Northwest National Laboratory's
POF	Probability of Failure
ROW	Right-of-Way

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Abbreviation	Term/Phrase/Name
SIM	Storm Impact Model
SLOSH	Sea, Land, and Overland Surges from Hurricanes
SPP	Storm Protection Plan
T&D	Transmission and Distribution
TEC	Tampa Electric Company

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1.0 EXECUTIVE SUMMARY

Tampa Electric Company (TEC) engaged the services of 1898 & Co, the advisory and technology consulting arm of Burns & McDonnell, to assist with the development of the 10-year Storm Protection Plan required by Florida Statute 366.96, also known as Senate Bill 796. In collaboration, TEC and 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and prioritize investment in the Transmission and Distribution (T&D) system utilizing a Storm Resilience Model. The Storm Resilience Model evaluates each hardening project's ability to reduce the magnitude and/or duration of disruptive storm events. Key objectives for the Storm Resilience Model are:

1. Calculate the customer benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level that maximizes customers benefit while not exceeding TEC technical execution constraints

While the resilience benefit is significant and is the focus of this report, it is not the only benefit of TEC's Storm Protection Plan. Additional benefits are described and quantified elsewhere in TEC's Plan. The Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit of hardening projects in terms of the range of reduced restoration costs and Customer Minutes Interrupted (CMI). The hardening projects provide resilience benefit from several perspectives. Some of the hardening projects eliminate storm-based outages all together, some reduce the number of customers impacted (CI), and others decrease the duration of storm-related outages. This report shows only the reduction in CMI, which accounts for both types of benefits. However, there is a strong relationship between reduction in CMI and reduction in CI.

Resilience-based prioritization facilitates the identification of the hardening projects that provide the most benefit. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers will get the most value for the level of investment.

This report outlines project prioritization and benefits calculations for the following TEC storm hardening programs:

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- Distribution Lateral Undergrounding
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

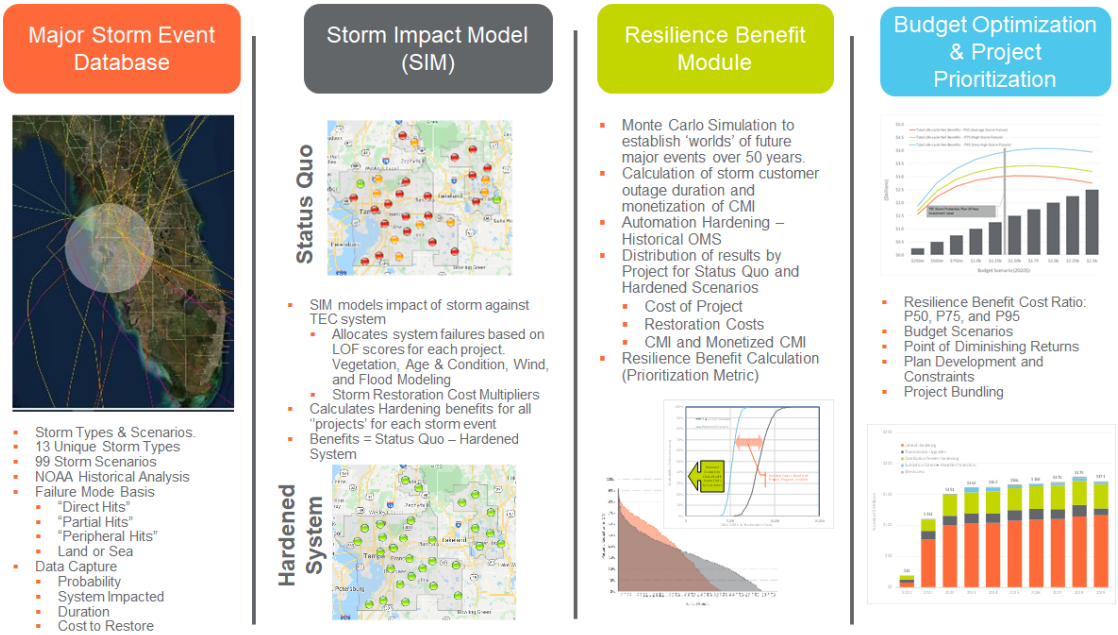
The other programs within TEC's Storm Protection Plan, Vegetation Management, Infrastructure Inspections, and Distribution Pole Replacements, are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's Storm Protection Plan. Similarly, their benefits are described in other portions of TEC's Storm Protection Plan.

1.1 Resilience Based Planning Approach

Figure 1-1 provides an overview of the Storm Resilience Model. The model employs a resilience-based planning approach to calculate the benefits of reducing storm restoration costs, CI, and CMI. Each of the different components are reviewed in further detail in Sections 3.0, 4.0, 5.0, and 6.0.

The Major Storm Events Database contains 13 unique storm types with a range of probabilities and impacts to create a total database of 99 different unique storm scenarios. The storm scenarios range from a Category 3 or greater direct hit from the Gulf of Mexico to a Category 1 or 2 partial hit over Florida, to a tropical storm. Section 3.0 provides additional details on the 99 different storm scenarios.

Figure 1-1: Storm Resilience Model Overview



Each storm scenario is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Likelihood of Failure (LOF) is based on the vegetation density around each conductor asset, the age and condition of the asset base, and the applicable wind zone for the asset's location. The Resilience Model is comprehensive in that it evaluates nearly all TEC's T&D system. Table 1-1 provides an overview of the potential project count for each of the programs.

Table 1-1: Potential Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	1,613
Transmission Access Enhancements	96
Total	20,459

The Storm Impact Model also estimates the restoration costs and CMI for each of the projects in Table 1-1 above for each storm scenario. For purposes of this report, the term "project" refers to a collection of assets. Assets are typically organized from a customer impact perspective, see Section 2.2. Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is

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hardened per TEC's hardening standards. The CMI benefit is monetized using the DOE's Interruption Cost Estimator (ICE) for project prioritization purposes.

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future storm worlds and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

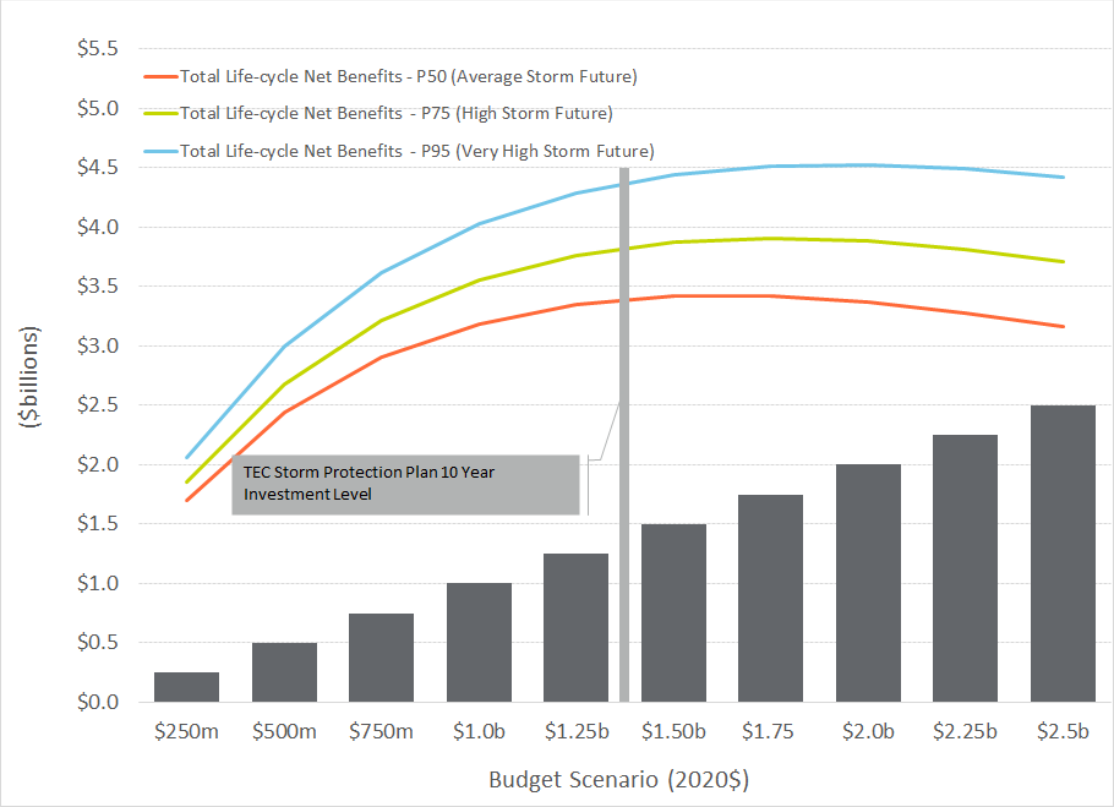
The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest resilience benefit cost ratio. It also performs a budget optimization over a range of budget levels to identify the point of diminishing returns.

The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates TEC's technical and operational constraints in scheduling the projects such as contractor capacity and scheduling planned transmission outages. Using the Resilience Benefit Calculation and Project Scheduling and Budget Optimization model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

1.2 Results & Conclusions

TEC and 1898 & Co. utilized a resilience-based planning approach to establish an overall budget level and identify and prioritize resilience investment in the T&D system. Figure 1-2 shows the results of the budget optimization analysis. Given the total level of potential investment, the budget optimization analysis was performed in $250 million increments up to $2.5 billion. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95. P50 to P65 levels represent a future world in which storm frequency and impact are close to average, P70 to P85 level represent a future world where storms are more frequent and intense, and P90 and P95 levels represent a future world where storm frequency and impacts are all high.

Figure 1-2: Budget Optimization Results

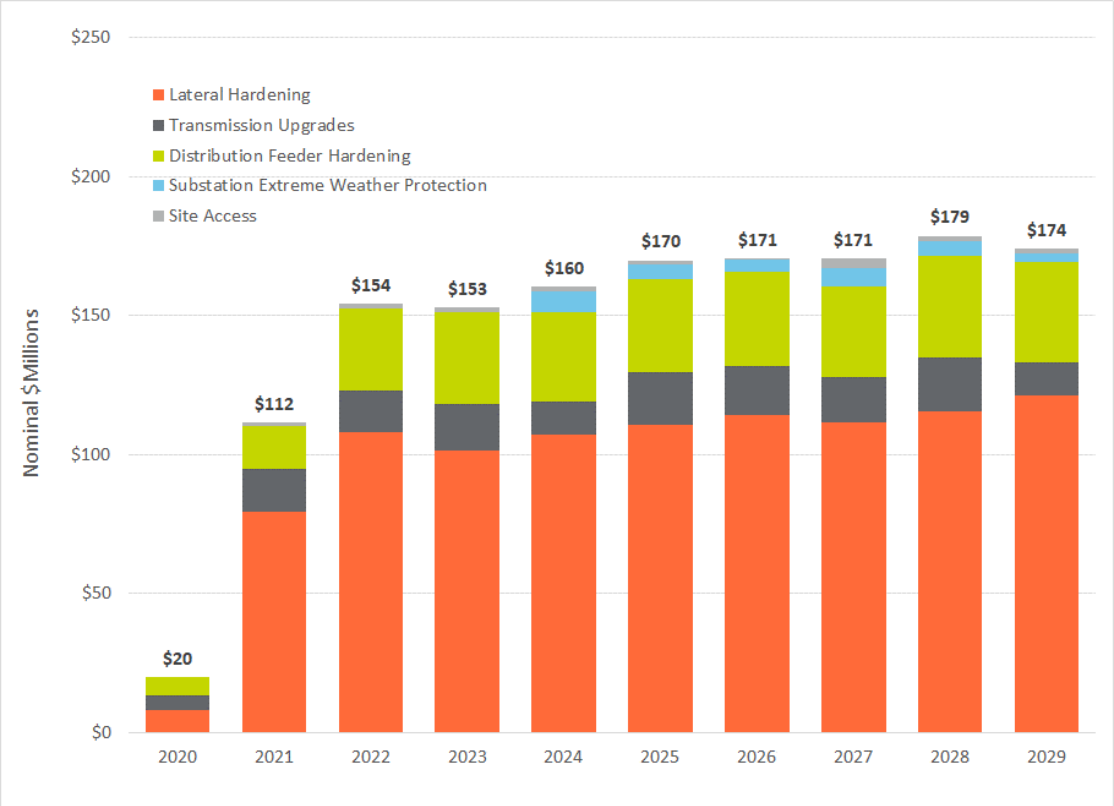


The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion budget scenarios with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2020 dollars for the TEC Storm Protection Plan. The TEC overall investment level is right before the point of diminishing returns, which demonstrates that TEC's plan has an appropriate level of investment over the next 10 years capturing the hardening projects that provide the most value to customers.

Figure 1-3 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan investment level is approximately $1.46 billion. Lateral undergrounding makes up most of the total, accounting for 66.8 percent of the total investment. Feeder Hardening is second accounting for 19.8 percent. Transmission upgrades make up approximately 10.2 percent of the total with substations and transmission site access making up 2.2 percent and 1.0 percent, respectively. The plan

includes a few months of investment in 2020 and a ramp-up period to levelized investment (in real terms) in 2022.

Figure 1-3: Storm Protection Plan Investment Profile

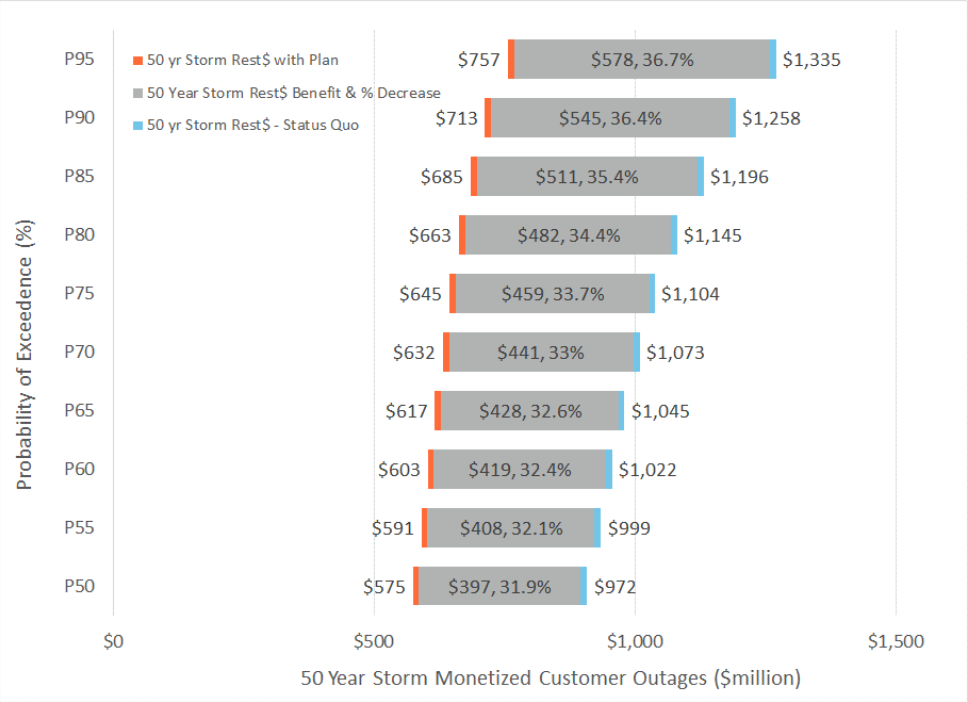


Customer benefits are calculated in terms of the:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

Figure 1-4 shows the range in restoration cost reduction at various probability of exceedance levels. To reiterate, the P50 to P65 level represents a future world in which storm frequency and impact are close to average, the P70 to P85 levels represent a future world where storms are more frequent and intense, and the P90 and P95 levels represent a future world where storm frequency and impacts are all high.

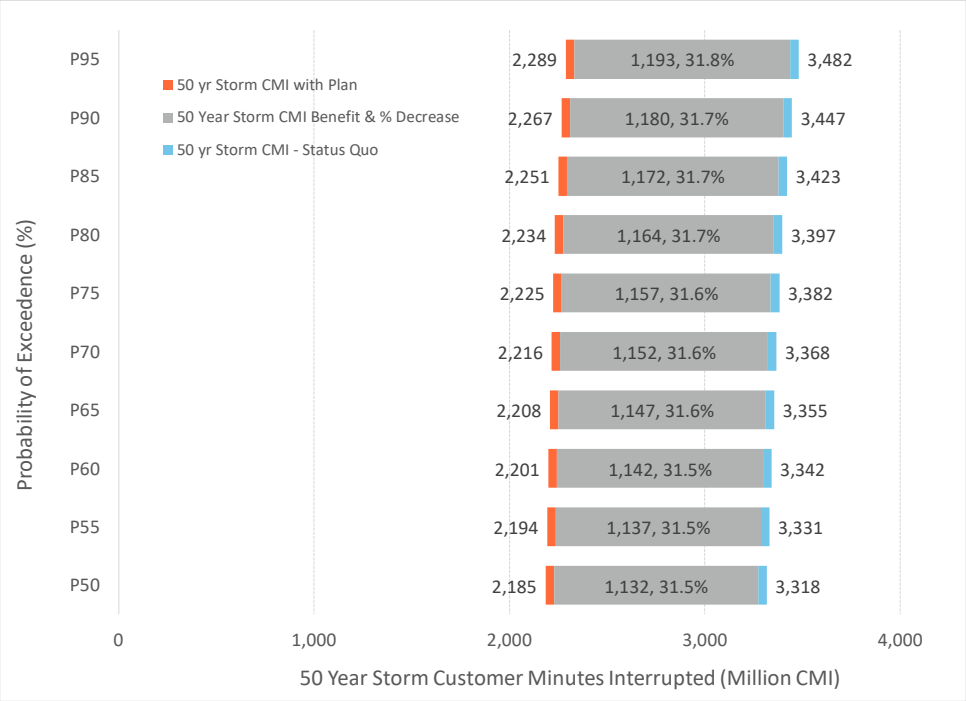
Figure 1-4: Storm Protection Plan Restoration Cost Benefit



The figure shows that the 50-year NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the restoration costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to $580 million. From an NPV perspective, the restoration cost benefit is approximately 36 to 53 percent of the Storm Protection Plan Investment Level. In other words, the reduction in restoration costs pay for 36 to 53 percent of the total invested capital costs.

Figure 1-5 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 32 percent decrease in the storm CMI over the next 50 years.

Figure 1-5: Storm Protection Plan Customer Benefit



The following include the conclusions of TEC's Storm Protection plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.46 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 1-2) shows the investment level is right before the point of diminishing returns.
- TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 32 to 37 percent. In relation to the plan's capital investment, the restoration costs savings range from 36 to 53 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 32 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.
- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.61 to $0.82 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.

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- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.
- The hardening investment will provide additional 'blue sky' benefits to customers not factored into this report.

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2.0 INTRODUCTION

Hurricanes have inflicted significant damage to Florida in recent years and parts of the state face years of recovery. One of the most important things Florida can do to prepare for the next major storm is to make the electric grid more resilient. When the grid can better withstand the impacts of storms, everyone benefits. Florida businesses and families save money because they can get back on their feet more quickly[1]. Florida Statute 366.96 allows for the comprehensive planning and front-end investment necessary to protect Florida's power supply. It also allows utilities to design integrated programs to address all phases of resilience which, in turn, will reduce storm-related restoration costs and outage times.

This document outlines the approach to

1. Calculate the benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level that maximizes customers' benefit while not exceeding TEC technical execution constraints

The resilience-based approach is an integrated data driven decision-making strategy comparing various storm hardening projects on a normalized and consistent basis. This approach takes an integrated asset management perspective, a bottom-up approach starting at the asset level. Each asset is evaluated for its likelihood of failure in a storm event. Additionally, the consequence of failure is also evaluated at the asset level in terms of the restoration costs and CMI. Assets are rolled up to hardening projects and hardening projects are then rolled up to programs. Each project only hardens the assets that provide the most benefit to customers and that align with TEC's design standards.

This report outlines project prioritization and benefits calculations for the following TEC storm hardening programs:

- Distribution Lateral Undergrounding
- Transmission Asset Upgrades

[1] State Rep. Randy Fine and State Sen. Joe Gruters, Sun Sentinel, May 2019

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- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

The other programs within TEC's Storm Protection Plan, Vegetation Management, Infrastructure Inspections, and Distribution Pole Upgrades, are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's Storm Protection Plan. Similarly, their benefits are described in other portions of TEC's Storm Protection Plan.

The following sections outline the foundation and background necessary to understand the rest of this report. These sections include a review of:

- Topic of resilience
- Resilience as the project assessment approach
- TEC asset base evaluated for resilience measures
- Resilience-based planning approach
- Resilience Investment Business Case Results

2.1 Resilience as the Benefits Assessment

Resilience has many faces. It looks different to different people and organizations depending on their challenges and focus. Is it more important to avoid an event from disrupting your business or is it more important to recover quickly? Both are important and TEC's approach considers both of these questions and more.

Resilience has been defined differently by many organizations. In a 2013 paper, the National Association of Regulatory Utility Commissioners (NARUC) paraphrased its own definition of resilience in a manner that is simple and easy to understand.

> *"it's the gear, the people and the way the people operate the gear immediately before, during and after a bad day that keeps everything going and minimizes the scale and duration of any interruptions."*

Before that, the National Infrastructure Advisory Council (NIAC) provided a definition that is often quoted, and which includes elements used in many other definitions. It states that resilience is

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> *"The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."*

The NIAC definition includes a system's ability to absorb and adapt. These important characteristics were also used by Argonne National Laboratory (ANL) in its work on state and social resilience and were incorporated into Pacific Northwest National Laboratory's (PNNL) work on the resilience impacts of transactive energy systems. The ANL approach can be used to break resilience into four phases that also align with NARUC's elegantly simple description. The difference is that ANL explicitly includes the ability of the system to recognize and mitigate potential failures before they happen. These four phases are described below.

- Prepare (Before)
  The grid is running normally but the system is preparing for potential disruptions.
- Mitigate (Before)
  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption. During this time the precursors are normally detectable.
- Respond (During)
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).
- Recover (After)
  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.

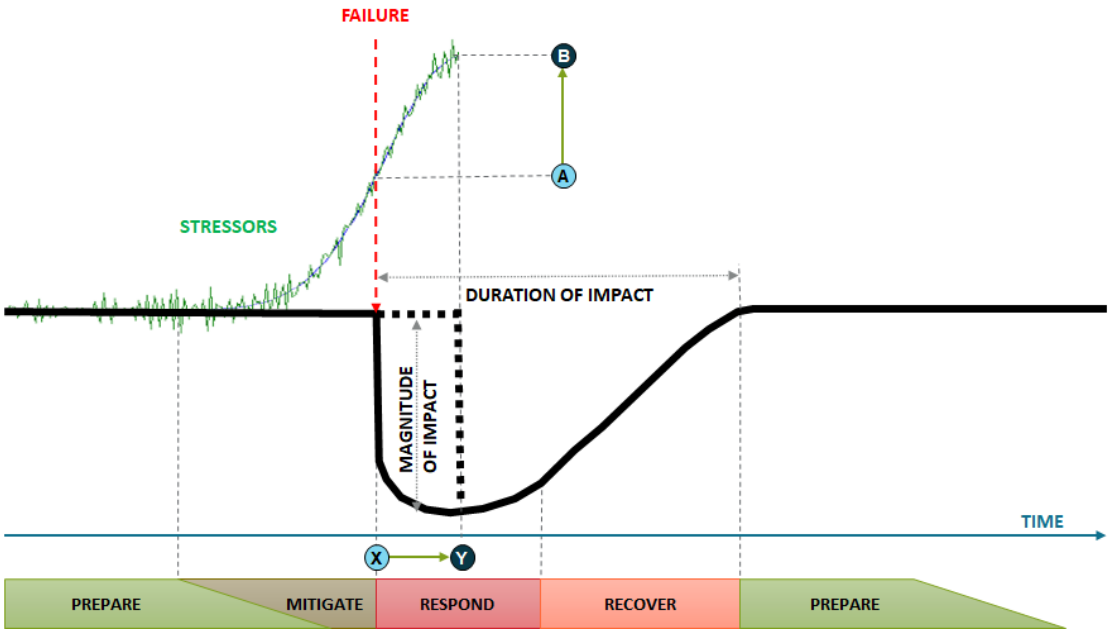
This is depicted graphically in Figure 2-1. The green line represents an underlying issue that is stressing the grid, and which increases in magnitude until it reaches a point where it impacts the operation of the grid and causes an outage. The origin of the stress may be electrical due to a failing component, or external due to storms or other events. The black line shows the status of the entire system or parts of the system (e.g. transmission circuits). The "pit" depicted after the event occurs represents the impact on a system in terms of the magnitude of impact (vertical) and the duration (horizontal). For utilities this can be measured after the event and is used by the Institute of Electrical and Electronics Engineers

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(IEEE) 1366 to calculate reliability metrics. If TEC is able to detect the strain on the grid caused by these stresses then it increases the opportunity to act before a failure occurs, thus reducing or avoiding the impact of the subsequent event.

Figure 2-1 represents a conceptual view of resilience. It can be used to depict a specific transmission line or the whole transmission system. If the figure is used to represent a specific line, it represents the impact of the event on that line. If the figure is used to represent the impact on the whole TEC system, it represents the aggregated impacts of the event (storm) and the multiple outages that may result from it. Note that whether this is a specific or overall depiction of resilience there is no quantification of time. Time increases from left to right but due to the nature of events that may occur there are no timescales used.

Figure 2-1: Phases of Resilience



For example, hardening of the overhead transmission system is targeted at the “prepare” phase. Mitigation depends on the ability to detect developing issues and includes the capability to detect stresses on the grid by monitoring it. Responding to an event as it is impacting the grid depends on the ability to make informed decisions, to deploy crews rapidly to the right place at the right time, and for the grid to adapt to the stresses through reconfiguration. Recovery depends on coordinated activity and good planning.

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In Figure 2-1, the level of strain on the grid caused by the early effects of an event that could cause asset failure is represented by 'A'. As an example, this might be a wooden transmission pole, with failure occurring at time 'X'. In this example suppose a steel monopole was used to replace the wood pole transmission structure. The monopole might succumb to failure at higher strain levels depicted by 'B' and would result in later failure at time 'Y'.

For the line where this occurred, this illustrates how hardening did not prevent failure but delayed it and shortened the outage duration. If it takes more work to erect a new monopole it might increase recovery time for a specific line, yet if less steel monopoles failed relative to the number of wood poles that would have failed, there would be less to replace and the overall system outage time and recovery time would be reduced. Fewer asset failures means that more crews will be able to work on the assets that do fail, which can have a multiplying effect on outage reduction time.

The Storm Resilience Model evaluates the phases of resilience for storms on both the entire system and at the sub-system level (substations, transmission circuit, site access, feeder, and lateral). Section 2.3 provides additional detail on this evaluation approach.

2.2 Evaluated System for Resilience Investment

The Storm Resilience Model (described in more detail in Section 2.3) is comprehensive in that it evaluates nearly all of TEC's T&D system. Table 2-1 shows the asset types and counts included in the Storm Resilience Model.

Table 2-1: TEC Asset Base Modeled

Asset Type	Units	Value
Distribution Circuits	**[count]**	**668**
Feeder Poles	[count]	35,200
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,200
Lateral OH Primary	[miles]	3,800
Transmission Circuits	**[count]**	**207**
Wood Poles	[count]	3,800
Steel / Concrete / Lattice Structures	[count]	17,700
Conductor	[miles]	1,300
Substations	**[count]**	**255**
Site Access	**[count]**	**96**
Roads	[count]	70
Bridges	[count]	26

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All of the assets are strategically grouped into potential hardening projects, and only the assets that require hardening are included in the projects. For distribution projects, assets were grouped by their most upstream protection device, which was either a breaker, a recloser, trip savers, or a fuse. This approach focuses on reducing customer outages. The objective is to harden each asset that could fail and result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves weak links that could potentially fail in a storm. Rolling assets into projects at the protection device level allows for hardening of all weak links in the circuit and for capturing the full benefit for customers.

For lateral projects, those with a fuse or trip saver protection device, the preferred hardening approach is to underground the overhead circuits. Since the main cause of storm related outages, especially for weakened structures, is the wind blowing vegetation into conductor, causing structure failures, undergrounding lateral lines provides full storm hardening benefits. While rebuilding overhead laterals to a stronger design standard (i.e. bigger and stronger poles and wires) would provide some resilience benefit, it would not solve the vegetation issues, since the high wind speeds can blow tree limbs from outside the trim zone into the conductor.

For distribution feeder projects, those with a recloser or breaker protection device, the preferred hardening approach is to rebuild to a storm resilient overhead design standard and add automation hardening. Assets in these projects include older wood poles and those with a ‘poor’ condition rating. Additionally, poles with a class that is not better than ‘2’ were also included in these projects. The combination of the physical hardening and automation hardening provides significant resilience benefit for feeders. The physical hardening addresses the weakened infrastructure storm failure component. While the vegetation outside the trim zone as still a concern, most distribution feeders are built along main streets where vegetation densities outside the trim zone are typically less than compared to laterals. Further, the feeder automation hardening allows for automated switching to perform ‘self-healing’ functions to mitigate vegetation outside trim zone and other types of outages. The combination of the physical and automation hardening provide a balanced resilience strategy for feeders. It should be noted that this balanced strategy with automation hardening is not available for laterals. As such, undergrounding is preferred approach for lateral hardening and overhead physical hardening combined with automation hardening is the preferred approach for feeders.

At the transmission circuit level, wood poles were identified for hardening by replacing with non-wood materials like steel, spun concrete, and composites. These materials have consistent internal strength while wood poles can vary widely and are more likely to fail. Transmission wood poles were grouped at the circuit level into projects.

TEC identified 96 separate transmission access, road, and bridge projects based on field inspection of the system.

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH model identified 59 substations with a flood risk, depending on the hurricane category.

Table 2-2 contains a list of potential hardening projects based on the methodology outlined above. As seen below, there are a significant number of potential hardening projects, over 20,000. The following sections outline the approach to selecting the hardening projects that provide the most value to customers from a restoration cost and CMI decrease perspective.

Table 2-2: Potential Hardening Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	1,613
Transmission Access Enhancements	96
Total	20,459

2.3 Resilience Planning Approach Overview

The resilience-based planning approach calculates the benefit of storm hardening projects from a customer perspective. This approach calculates the resilience benefit at the asset, project, and program level within the Storm Resilience Model. The results of the Storm Resilience Model are a:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

Figure 2-2 provides an overview of the resilience planning approach to calculate the customer benefit, restoration cost reduction and CMI reduction of hardening projects and prioritization of the projects.

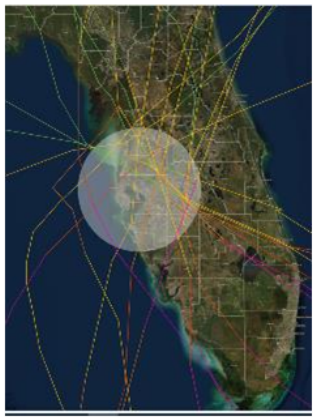
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2.3.1 Major Storms Event Database

Since the magnitude of the restoration cost decrease and CMI decrease is dependent on the frequency and magnitude of future major storm events, the Storm Resilience Model starts with the 'universe' of major storm events that could impact TEC's service territory, the Major Events Storms Database.

Figure 2-2: Resilience Planning Approach Overview

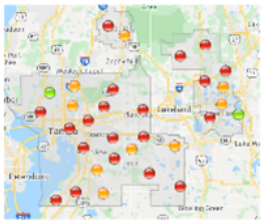
Major Storm Event Database



- Storm Types & Scenarios.
- 13 Unique Storm Types
- 99 Storm Scenarios
- NOAA Historical Analysis
- Failure Mode Basis
  - "Direct Hits"
  - "Partial Hits"
  - "Peripheral Hits"
  - Land or Sea
- Data Capture
  - Probability
  - System Impacted
  - Duration
  - Cost to Restore

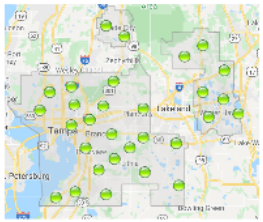
Storm Impact Model (SIM)

Status Quo



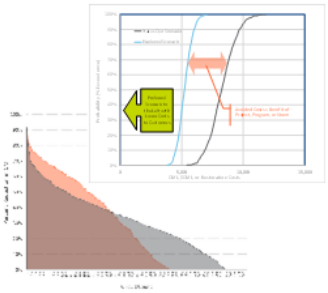
- SIM models impact of storm against TEC system
  - Allocates system failures based on LOF scores for each project. Vegetation, Age & Condition, Wind, and Flood Modeling
  - Storm Restoration Cost Multipliers
- Calculates Hardening benefits for all "projects' for each storm event
- Benefits = Status Quo – Hardened System

Hardened System

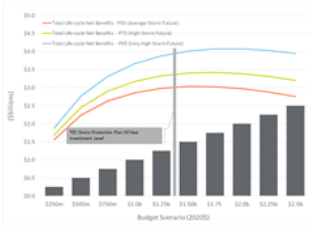


Resilience Benefit Module

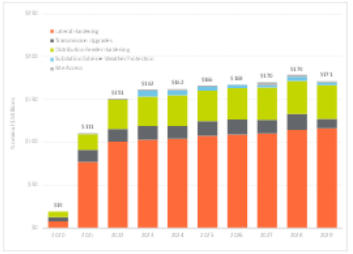
- Monte Carlo Simulation to establish 'worlds' of future major events over 50 years.
- Calculation of storm customer outage duration and monetization of CMI
- Automation Hardening – Historical OMS
- Distribution of results by Project for Status Quo and Hardened Scenarios
  - Cost of Project
  - Restoration Costs
  - CMI and Monetized CMI
- Resilience Benefit Calculation (Prioritization Metric)



Budget Optimization & Project Prioritization



- Resilience Benefit Cost Ratio: P50, P75, and P95
- Budget Scenarios
- Point of Diminishing Returns
- Plan Development and Constraints
- Project Bundling



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The Major Storms Event Database describes the stressor that causes system failure. The database also provides the high-level impact to the system of the storm stressor. The major events database includes the following:

- Storm Type
- Probability of a storm occurring
- Restoration Costs
- Percentage of the system impacted
- Duration of the storm

The major storm events database includes 13 unique storm types. The storm types include the various hurricane categories and direction they come from (hurricane impacts from the Gulf side are much different than from the Florida side). Each storm type has a range of probabilities and impacts. With the various combinations (high probability with lower consequence and low probability with high consequence, etc.) the Major Storms Event Database includes 99 different storm scenarios. Section 3.0 provides additional detail on the Major Storms Event Database.

2.3.2 Storm Impact Model

Each storm scenario is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Storm Impact Model calculates the restoration costs and customers impacted by system failures for both the Status Quo and Hardened Scenarios. The Storm Impact Model identifies the damaged portions of the system by modeling the elements that cause failures in the TEC asset base.

For circuits, the main cause of failure is wind blowing vegetation onto conductor causing conductor or structures to fail. If structures (i.e. wood poles) have any deterioration, for example rot, they are more susceptible to failure. The Storm Impact Model calculates a storm LOF score for each asset based on a combination of the vegetation rating, age and condition rating, and wind zone rating. The vegetation rating factor is based on the vegetation density around the conductor. The age and condition rating utilize expected remaining life curves with the asset's 'effective' age, determined using condition data. The wind zone rating is based on the wind zone that the asset is located within. The Storm Impact Model includes a framework that normalizes the three ratings with each other to develop one overall storm LOF score for all circuit assets. The project level scores are equal to the sum of the asset scores normalized for length. The project level scores are then used to rank each project against each other to

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identify the likely lateral, backbone, or transmission circuit to fail for each storm type. The model estimates the weighted storm LOF based on the asset level scoring.

The model determines which substations are likely to flood during various storm types based on the flood modeling analysis. That analysis provides the flood level, meaning feet of water above the site elevation, for various storm types.

Each transmission site access project provides access to one or more transmission circuits. If a major storm event causes a transmission outage and the access location is also impacted, it can take longer to restore the system. The Storm Impact Model uses each transmission circuit's storm LOF to estimate the LOF of each site access during a storm. For instance, if site access 'A' is needed to gain access to Circuit '1' and '4', the storm likelihood for site access 'A' equals the storm likelihood of failure for Circuit '1' and '4' combined.

Once the Storm Impact model identifies the portions of the system that are damaged and caused an outage for a specific storm, it then calculates the restoration costs to rebuild the system to provide service. The restoration costs are based on the multipliers for storm replacement over the planned replacement costs using TEC labor and procured materials only. The restoration cost multipliers are based on historical storm events and the expected outside labor and expedited material cost needed to restore the system.

Similarly, the Storm Impact Model calculates the CMI for each project. Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset in the Storm Impact Model. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known customer count to calculate the CMI. The CMI benefit is monetized using DOE's ICE Calculator for project prioritization purposes.

Finally, the Storm Impact Model then calculates the reductions in project storm LOF, restoration costs, and CMI for each hardening project. The output of the Storm Impact Model is the project LOF, CMI, monetized CMI, and restoration costs for each of the 99 storms for both the Status Quo and Hardened scenarios.

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2.3.3 Resilience Benefit Calculation

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future "storm worlds" and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

2.3.4 Project Scheduling and Budget Optimization

The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest ratio of resilience benefit to cost. It also performs a budget optimization simulation to identify the point of diminishing returns for hardening investments for the 10 year period and portions of the system evaluated.

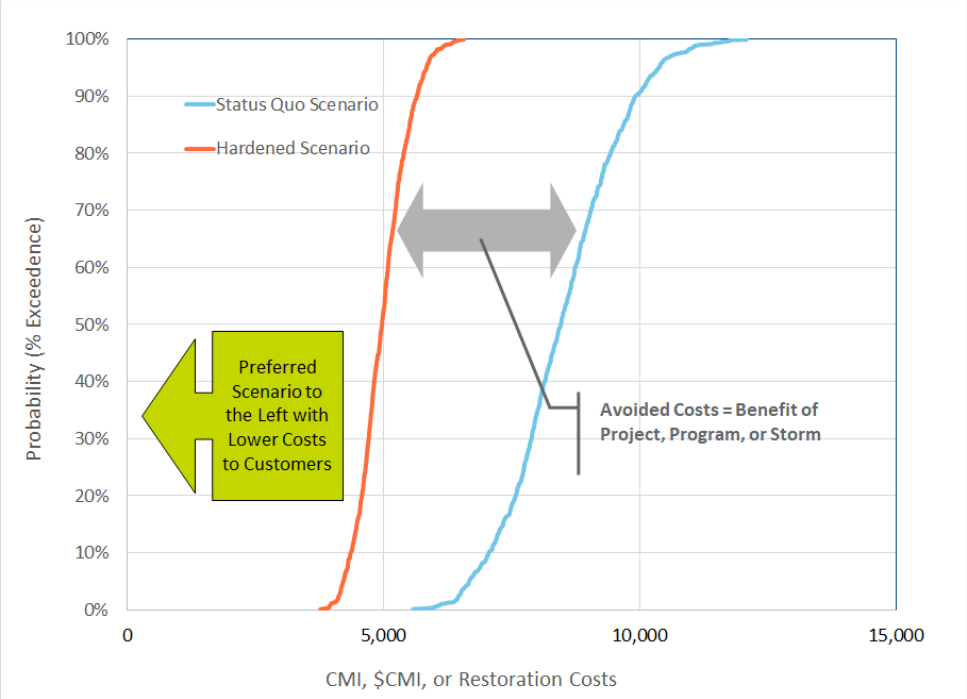
The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This calculation is performed for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates TEC's technical and operational constraints in scheduling the projects such as contractor capacity and scheduling transmission planned outages. Using the Resilience Benefit Calculation and project scheduling model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

Budget optimization is performed by running the model over a wide range of budget scenarios. Each budget scenario calculates the range in reduction of restoration costs and CMI. The budget optimization calculates the point where incremental hardening investments result in diminishing returns in customer benefit.

2.4 S-Curves and Resilience Benefit

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. In layman's terms, the thousand results are sorted from lowest to highest (cumulative ascending) and then charted. Figure 2-3 shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios.

Figure 2-3: Status Quo and Hardened Results Distribution Example

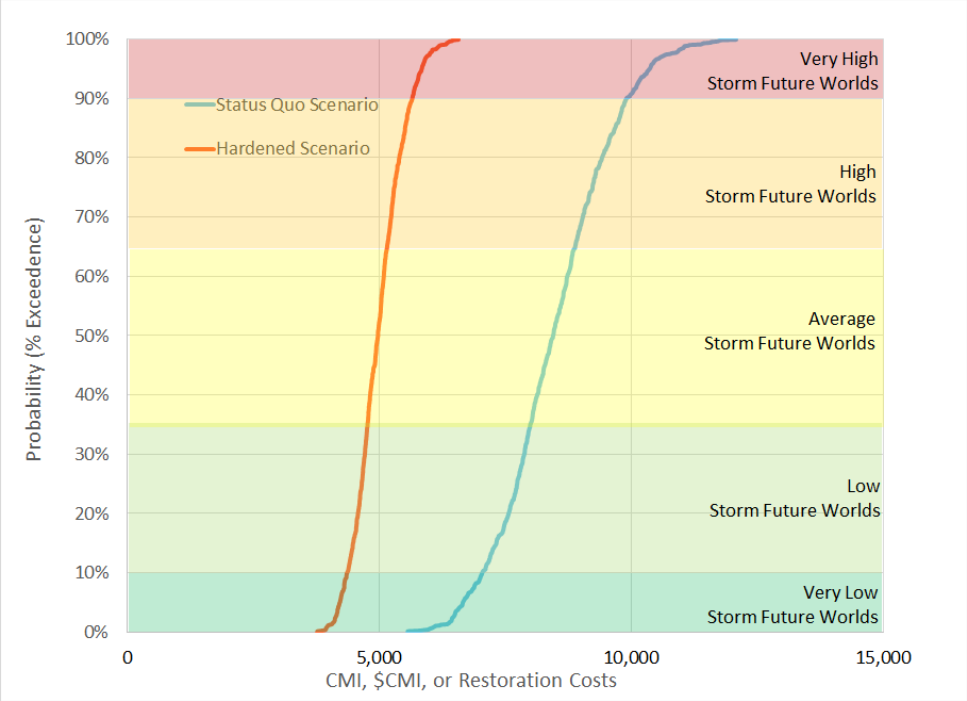


The horizontal axis shows the storm cost in terms of CMI, monetized CMI, or restoration costs. The values in the figure are illustrative. The vertical axis shows the percent exceedance values. For the Hardened Scenario, the chart shows a value of 5,000 at the 40-percentile level. This means there is a 40 percent confidence that the Hardened Scenario will have a value of 5,000 or less. Each of the probability levels is often referred to as the P-value. In this case the P40 (40 percentile) has a value of 5,000 for the Hardened Scenario.

Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

The S-Curves typically have a linear slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e. vertical) the less range in the result. The more horizontal the slope the wider the range and variability in the results. Figure 2-4 provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

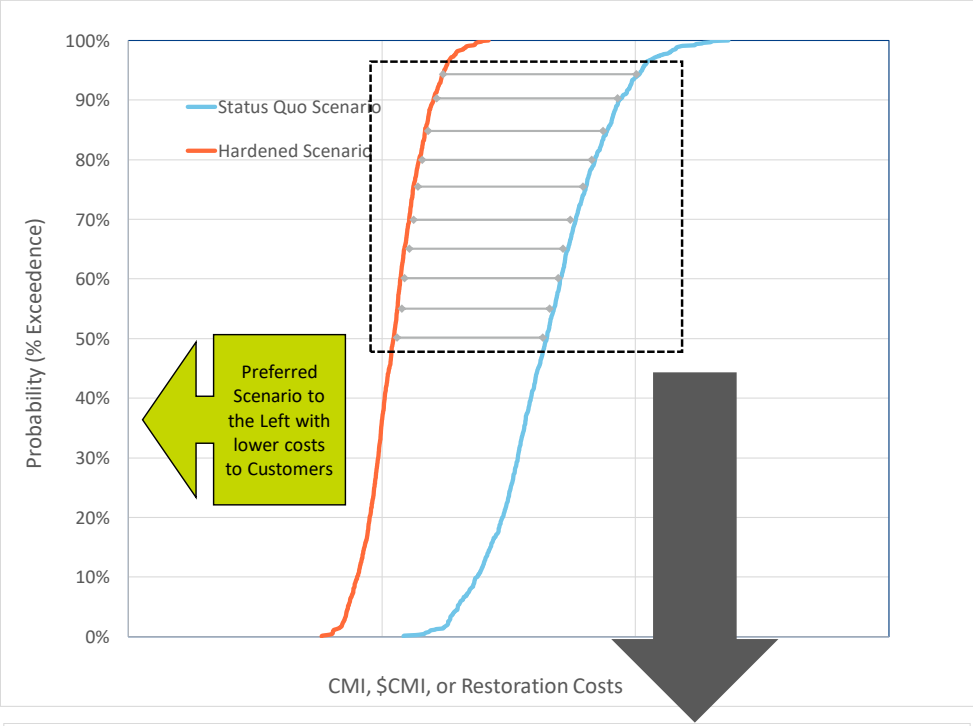
Figure 2-4: S-Curves and Future Storms

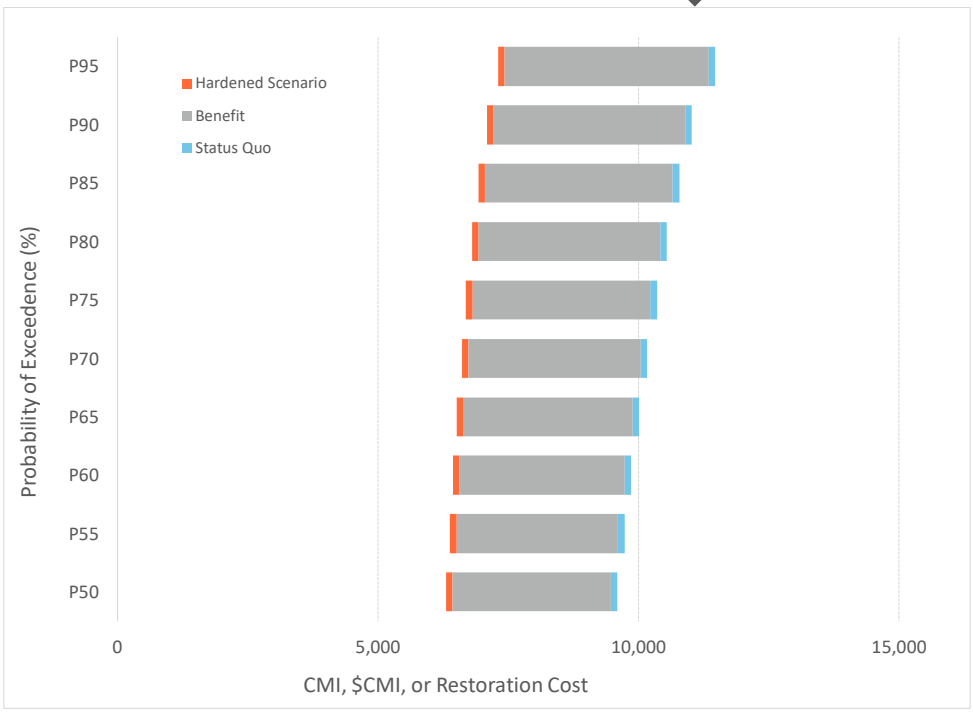


For the storm resilience evaluation, the top portion of the S-curves is the focus as it includes the average to very high storm futures, this is referred to as the resilience portion of the curve. Rather than show the entire S-curve, the results in the report will show specific P-values to highlight the gap between the 'Status Quo' and Hardened Scenarios. Additionally, highlighting the specific P-values can be more intuitive. Figure 2-5 illustrates this concept of looking at the top part of the S-curves and showing the P-values. Section 7.0 includes results figures similar to the second figure in Figure 2-5 below.

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Figure 2-5: S-Curves and Resilience Focus





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3.0 MAJOR STORMS EVENT DATABASE

The first main component of the Storm Resilience Model is the Major Storms Event Database. The database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for a range of storm stressors. This section describes the data sources and approach used to develop the database. Since the benefits of hardening projects are directly related to the frequency and impact of major storm events, the resilience-based planning approach starts with developing the range of storm types that could impact TEC's service territory. The impact of major storm events to the TEC system is dependent on following:

- Wind speeds of the storm (i.e. category of storm). Higher wind speeds means more trees and tree limbs from inside and outside of the tree trim zone on the conductor. The additional weight and forces on the conductor cause pole or tower failures. At high enough wind speeds, the wind speed alone can cause a structure failure.
- Direction that it comes from (Gulf or Florida). Storms from the Gulf could bring storm surge and associated flooding. Additionally, the counter-clockwise storm band rotation include different level of energy (i.e. wind speed) if they have been over land for a period of time.
- Eye Distance from TEC's territory. Storms that directly hit Tampa are impactful since the entire service territory effectively gets hit twice by the storm bands. Additionally, the total duration of the event is longer. For more distant storms, only a few storm bands may hit the TEC service territory.

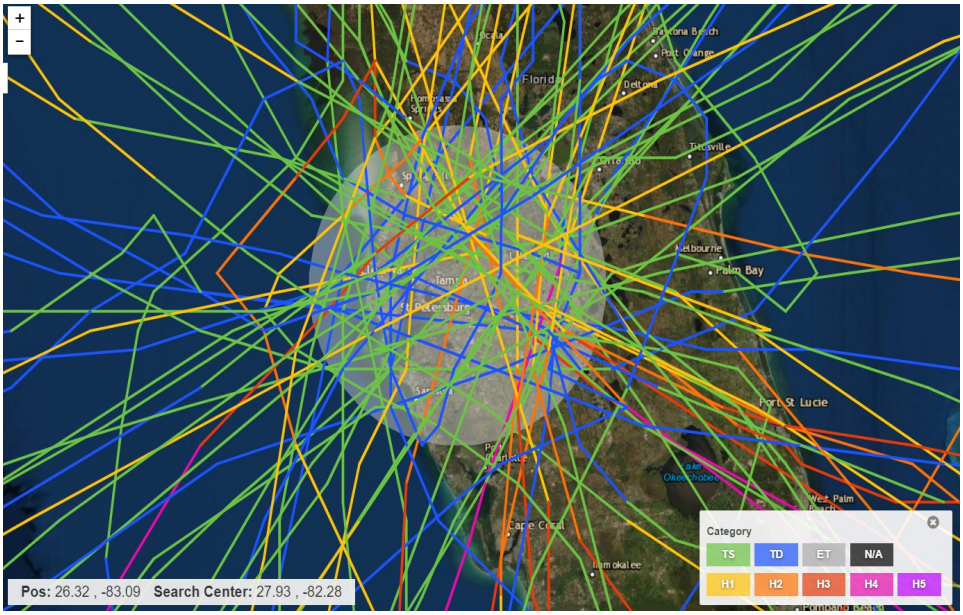
The major storms event database includes the range of storm stressors that would cause an outage(s) to the TEC system based on the three main contributing factors above. The database includes both the probability of the storm stressor, impact in terms of restoration costs and duration, and impact with respect to which parts of the TEC system fail. The following sections provide additional analysis and commentary on how these assumptions were developed for the storms event database.

3.1 Analysis of NOAA Major Storm Events

The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 167 years, beginning in 1852. This database was mined to evaluate the different types and frequency of major storms to impact the TEC service territory. Figure 3-1 provides an example screen

shot from NOAA's storms database. It shows all the events, including path and category, to come within 50 miles of TEC's service territory center.

Figure 3-1: NOAA Example Output – 50 Mile Radius



Source: https://coast.noaa.gov/hurricanes/

This database was mined for all major event types up to 150 miles from TEC service territory center. The 150-mile radius was selected since many hurricanes can have diameters of 300 miles where some of the hurricane storm bands impact a significant portion of the TEC service territory. Additionally, the database was mined for the category of the storm as it hit the TEC service territory. The analysis of NOAA's database was done for the following types of storm categories:

- 'Direct Hits' – 50 Mile Radius from the Gulf and Florida directions. The max wind speeds hit all or significant portions of TEC service territory twice, once from the front end and again on the back end of the storm. Additionally, the wind speeds cause all the assets and vegetation to move in one direction as the storm comes in and in the opposite direction as it moves out. This double exposure to the system causes significant system failures.
- 'Partial Hits' – 51 to 100 Mile Radius. At this radius, the storm bands hit a significant portion of the TEC service territory. Wind speeds are typically at their highest at the outer edge of the storm bands. The storm passes through the territory once, so to speak, minimizing damage

relative to a 'direct hit'. For large category storms, the 'Partial Hit' could still cause more damage than a 'Direct Hit' small storm.

- 'Peripheral Hits' – 101 to 150 Mile Radius. Since hurricanes can be 300 miles wide in diameter, some of the storm bands can hit a fairly large portion of the system even if the main body of the storm misses the service area.

Table 3-1 includes the summary results from the NOAA database of storms to hit or nearly hit the TEC service territory since 1852.

Table 3-1: Historical Storm Summary

Event Type	Direct Hits Gulf	Direct Hits Florida	Direct Hits Total	Partial Hits	Peripheral Hits	Total
Cat 5	0	0	0	0	0	0
Cat 4	0	1	1	0	1	2
Cat 3	0	1	1	5	4	10
Cat 2	4	1	5	2	8	15
Cat 1	6	6	12	14	8	34
Tropical Storm	11	20	31	29	28	88
Tropical Depression	10	8	18	17	NA	35
Total	31	37	68	67	49	184

Table 3-1 shows a total of 184 storms to hit the Tampa area since 1852. A total of 68 were direct hits within 50 miles, 67 were partial hits in the 51 to 100-mile radius, and 49 were peripheral hits in the 101 to 150 mile radius. The table also shows very few category 4 and above events, 2 out of 184, with one 'Direct Hit'. While there are 10 Category 3 types storms, only 1 is a 'Direct Hit'. Nearly 20 percent of the events are Category 1 Hurricanes. Almost two thirds of the events are Tropical Storms or Tropical Depressions. For direct hits, the results show approximately 46 percent of the events come from the Gulf of Mexico while the other 54 percent come over Florida. The direction the storm comes from has significant impact on the overall damage to TEC's system. Based on these results and the various

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quantities by event type, the following 13 unique storm types serves as the foundation for the Major Storms Event Database:

1. Category 3 and Above 'Direct Hit' from the Gulf
2. Category 1 & 2 'Direct Hit' over Florida
3. Category 1 & 2 'Direct Hit' from the Gulf
4. Tropical Storm 'Direct Hit'
5. Tropical Depression 'Direct Hit'
6. Localized Event 'Direct Hit'
7. Category 3 and Above 'Partial Hit'
8. Category 1 & 2 'Partial Hit'
9. Tropical Storm 'Partial Hit'
10. Tropical Depression 'Partial Hit'
11. Category 3 and Above 'Peripheral Hit'
12. Category 1 & 2 'Peripheral Hit'
13. Tropical Storm 'Peripheral Hit'

Each of these storm types serve as a stressor on the system that causes an outage and damage. The next three subsections provide a historical analysis of storm events that impacted TEC's Service Territory to provide information on the probability of each of the 13 storm types.

3.1.2 Direct Hits (50 Miles)

Figure 3-2 provides a historical view of the number of major storm events to hit the TEC service territory over the last 167 years. The figure shows 6 different storm types. Figure 3-3 converts the storm data in Figure 3-2 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951. Review of the two figures shows there have been no Category 3 or above hurricanes to hit the TEC service territory from the Florida side.

Figure 3-2: "Direct Hits" (50 Miles) Over Time[2]

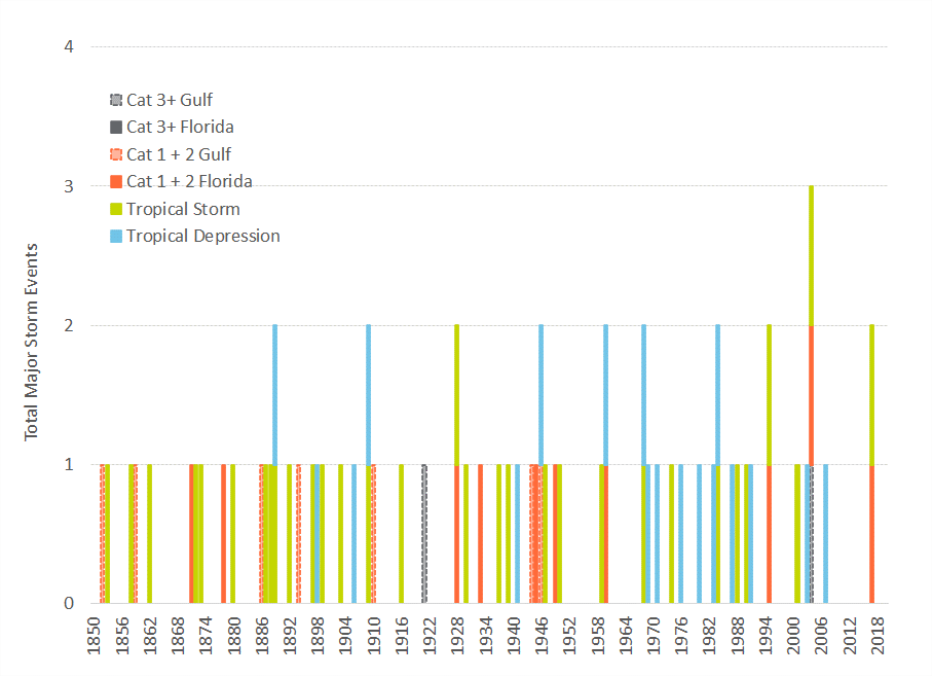


Figure 3-3 shows an average of approximately 40 storms for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Direct Hits' over the time horizon. The figure shows a relative stability in the number of Category 1 and above storms over the period. Even though there is relative stability in the 40-storm average for the 100-year rolling average time horizon, the figure shows a decrease in the number of tropical storms with a corresponding increase in the number of tropical depressions. Figure 3-4 converts the totals for each 100-year period in Figure 3-3 to probabilities by dividing by 100.

[2] Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Figure 3-3: "Direct Hits" (50 Miles) 100 Year Rolling Average[3]

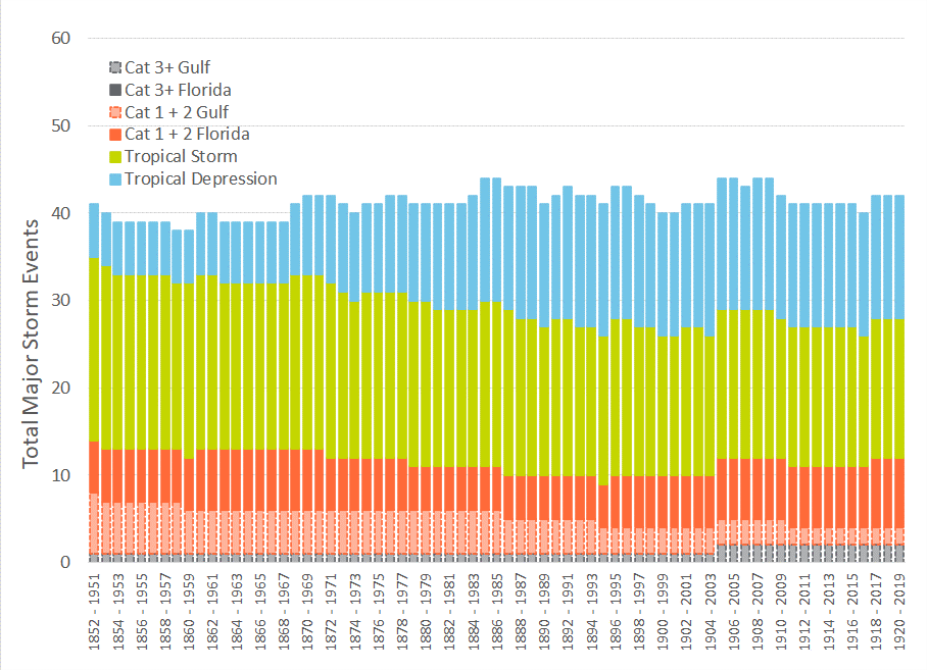
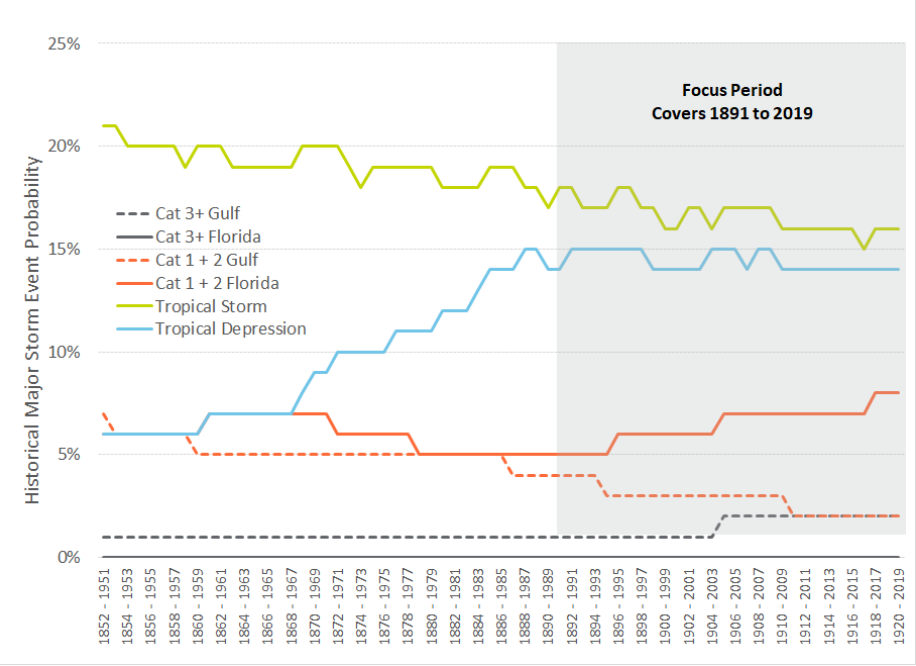


Figure 3-4: "Direct Hits" (50 Miles) 100 Year Rolling Probability[3]



[3] See Footnote 2

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The figure shows a low historical probability for Category 3 and above events from the Gulf of 1 to 2 percent. Additionally, there has been a decrease in the probability of Category 1 and 2 storms from the Gulf with a corresponding increase in the number coming from the Florida side. The story is similar for Tropical Storms and Tropical Depressions. The number of Tropical Storms shows a steady relative decline with a significant increase in probability of Tropical Storms until 1990 and stabilizes thereafter. As the figure shows, the probabilities of failure show a relative stability for the 100-year rolling average probabilities from 1990 to 2019, which encompasses thirty 100-year periods. Given the recent stability over this period these probability ranges were utilized in the Major Storms Event Database.

3.1.3 Partial Hits (51 to 100 Miles)

Figure 3-5 provides a historical view of the number of major storm events that have partially hit the TEC service territory over the last 167 years. A storm is classified as a partial hit if the eye passes between 51 and 100 miles from TEC's service territory. The figure shows 4 different storm types. Figure 3-6 converts the storm data in Figure 3-5 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951. The 100-year rolling average of storm events for partial hits follows a similar profile to that of direct hits, but it does show that Category 3 storms have hit TEC's service territory within a 51 to 100-mile radius throughout the rolling average windows in the analysis. This illustrates that there is a real possibility that TEC's service territory will be impacted by a Category 3 or higher hurricane each year.

Figure 3-5: "Partial Hits" (51 to 100 Miles)[4]

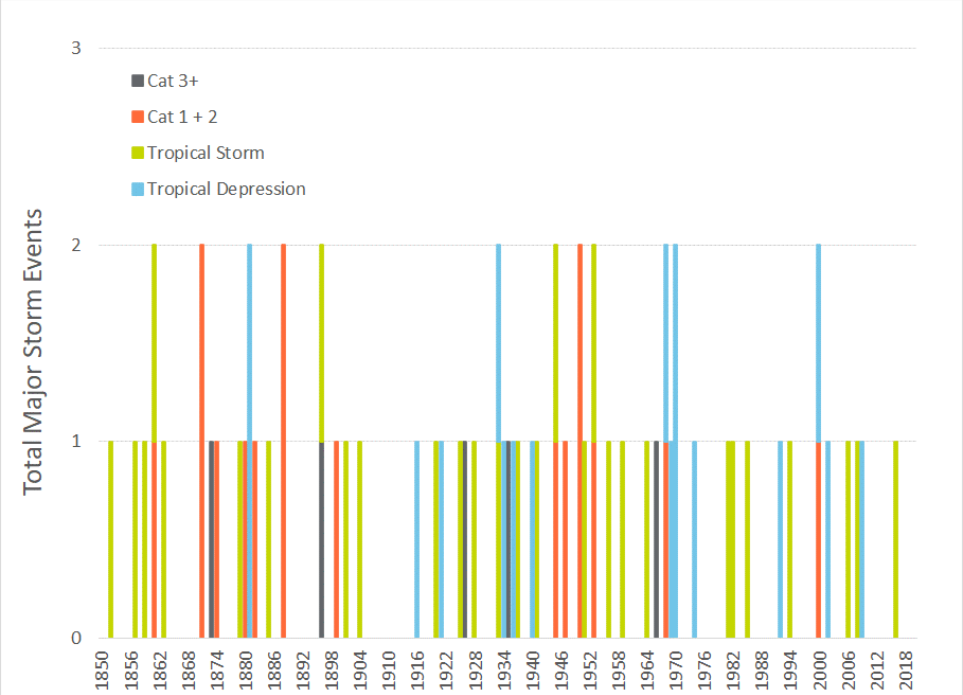


Figure 3-5 shows an average storm count of approximately 42 for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Partial Hits' over the time horizon. The figure shows a slight decline in the number of Category 1 and 2 storms over the period. As the overall storm count has remained stable, the slight decline in Category 1 and 2 storms was inversely mirrored by an increase in tropical depression counts.

Figure 3-7 converts the totals for each 100-year period in Figure 3-6 to probabilities by dividing by 100. This figure further illustrates the change in storm type distributions as Category 1 and 2 storms gave way to tropical depressions. The reason for the shift is unknown, but it is possible that this change is due to increases in data accuracy or recording procedures over time.

[4] See Footnote 2

Figure 3-6: "Partial Hits" (51 to 100 Miles) 100 Year Rolling Average[5]

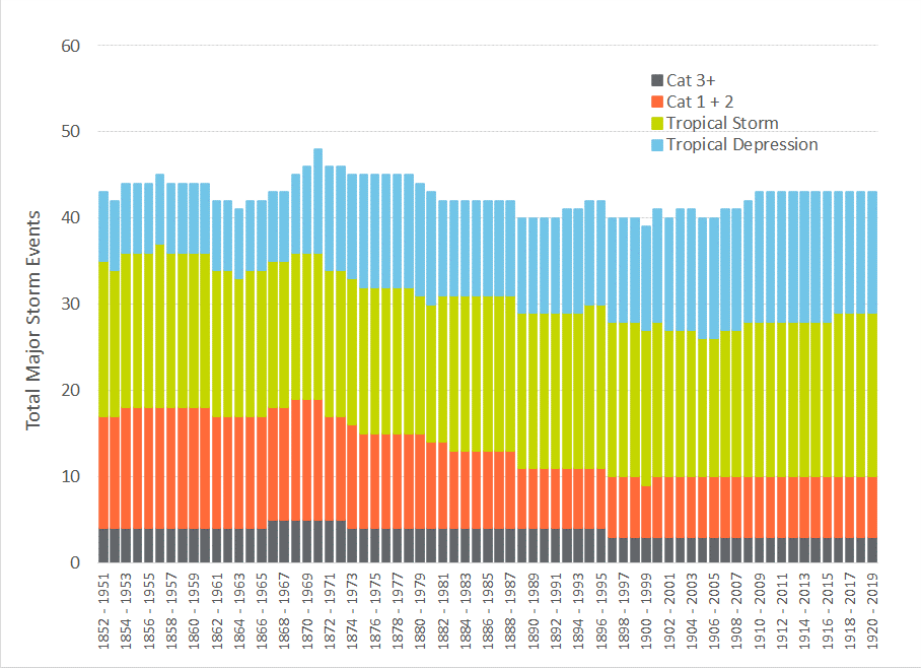
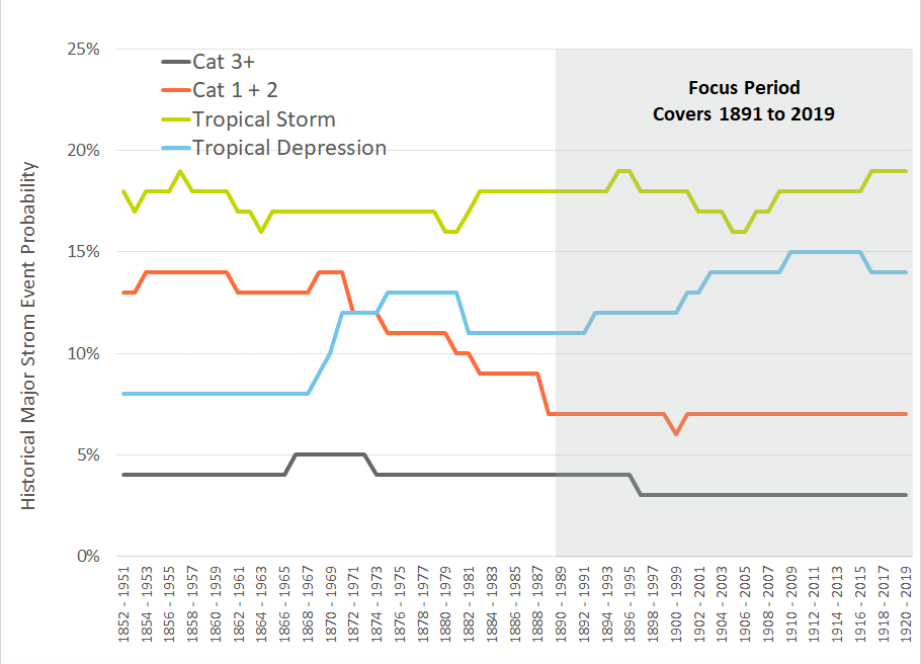


Figure 3-7: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[5]

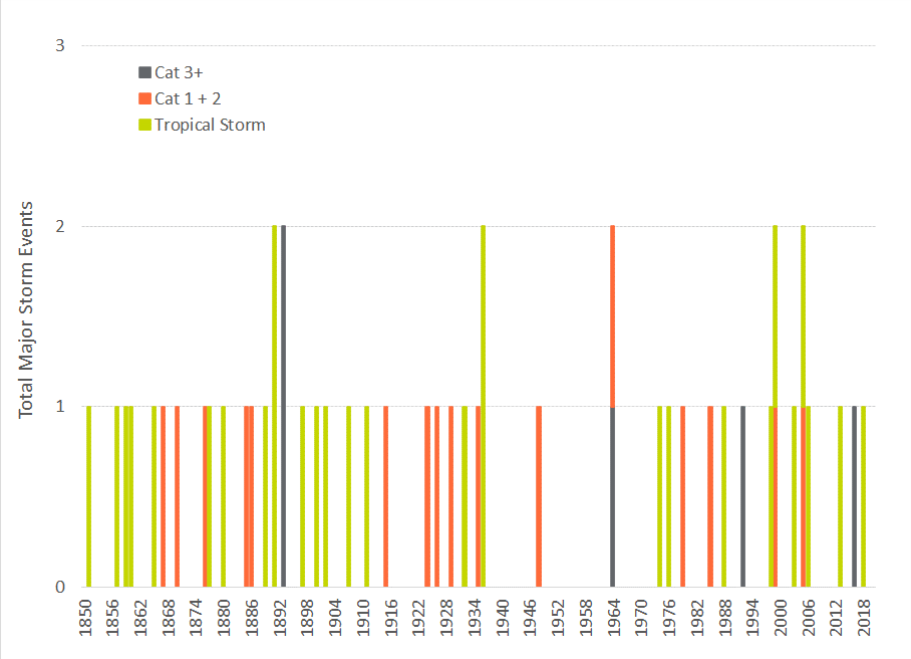


[5] See Footnote 2

3.1.4 Peripheral Hits (101 to 150 Miles)

Figure 3-8 provides a historical view of the number of major storm events that have hit TEC's service territory in the periphery over the last 167 years. A storm is classified as a partial hit if the eye passes between 101 and 150 miles from TEC's service territory. Since tropical depressions within this range may not be large enough to impact TEC's service territory, the figure only includes Tropical Storms, Category 1 and 2 storms, and Category 3 and higher storms. Figure 3-9 converts the storm data in Figure 3-8 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951.

Figure 3-8: "Peripheral Hits" (101 to 150 Miles)[6]



The 100-year rolling average of storm events for peripheral hits shows a slight decline from 30 to 25 storms, mostly driven by a decline in Tropical Storms.

Figure 3-10 converts the totals for each 100-year period in Figure 3-9 by dividing by 100. This figure further illustrates the decline in probability of Tropical Storms over the analysis period.

[6] See Footnote 2

Figure 3-9: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Avg.[7]

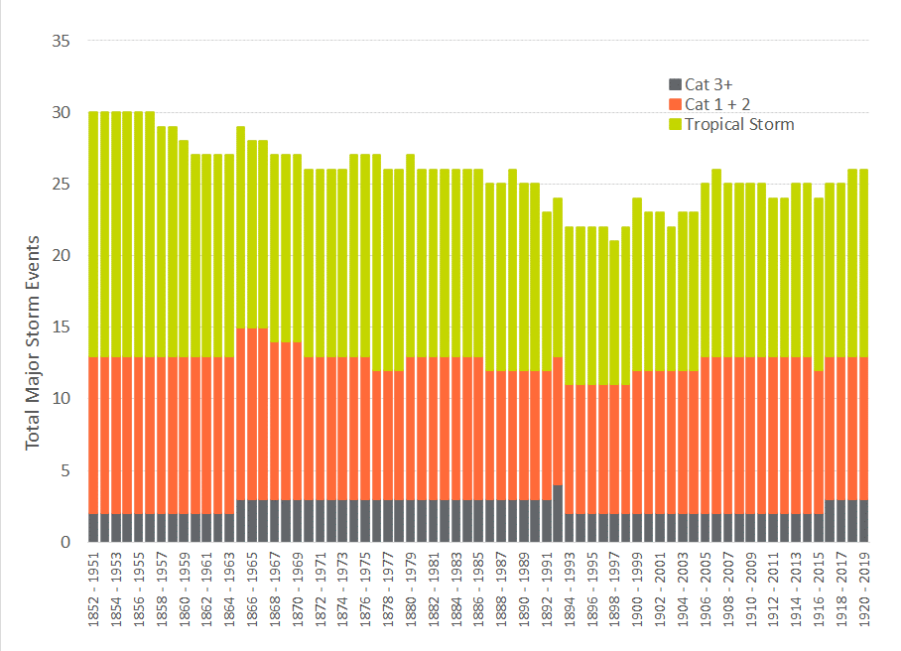
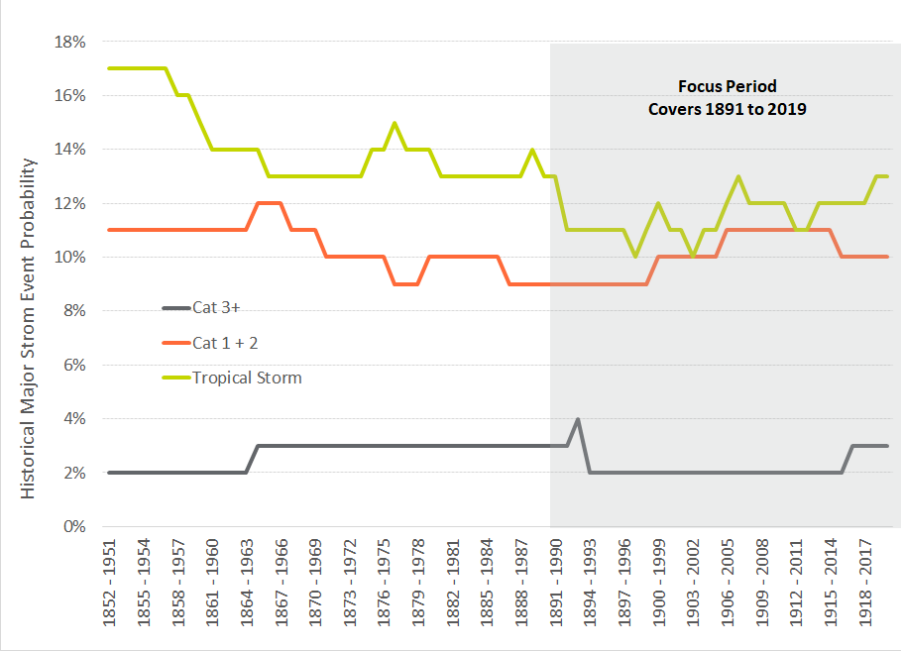


Figure 3-10: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[7]



[7] See Footnote 2

3.2 Major Storms in the Future

Section 3.1 reviewed the historical major events to hit the TEC service territory over the last 167 years. It is unclear whether climate change is affecting or will affect the frequency or severity of major storm events in the future. Research into this question reveals that there is no statistical evidence to support a higher frequency of major storm activity. The World Meteorological Organization provided the following comment:

> "Though there is evidence both for and against the existence of a detectable anthropogenic signal in the tropical cyclone climate record to date, no firm conclusion can be made on this point. However, research shows that there is evidence that the magnitude of the events are and will continue to increase."

Given this research, the Major Storm Event Database utilizes the historical probabilities for future storm probability. The impact of the events is discussed in the next section.

3.3 Major Storms Impact

Table 3-2 shows the damages cost of recent major storms to hit the Southeast United States. The table shows that the costs of these major events is significant.

Table 3-2: Recent Major Event Damages Cost

Storm Name	Category	Year	Damages (2018 $Billions)
Michael	5	2018	$25
Irma	4	2017	$51
Matthew	5	2016	$10
Wilma	3	2005	$10
Dennis	3	2005	$3
Jeanne	3	2004	$9
Ivan	3	2004	$19
Frances	2	2004	$12
Charley	4	2004	$19

The costs shown in the table are all damage costs to society and are based on insurance claims. The utility restoration costs are one element of this total. The TEC storm reports provide information on the restoration costs of historical events to hit the TEC service territory. Figure 3-11 provides a summary of the storm report for Hurricane Irma in 2017. It cost TEC approximately $100 million and restoration took slightly more than 7 days. Table 3-3 provides a summary of other recent TEC storm reports.

Figure 3-11: Hurricane Irma Impact to TEC Service Territory[8]

Storm Name: Irma

Year: 2017

TEC Cost: ~$100 million

Category: 1 over Florida

Radius: 50 Miles

Outage Duration: 7 Days

System Impact:
15 T-Lines
200 Circuits
55% of Customers

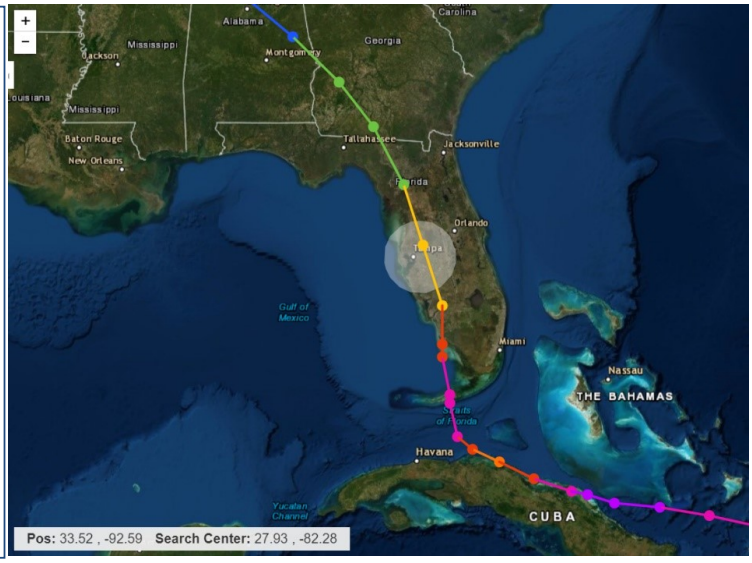


Table 3-3: Storm Report Summary

Storm Name	Category	Year	Damages (2018 $Millions)
Irma	1	2017	$102
Matthew	3	2016	$1
Hermine	1	2016	$6
Colin	TS	2016	$3

3.4 Major Storms Database

TEC and 1898 & Co collaborated in developing the Major Storm Events Database. The database utilizes the results of the NOAA analysis to identify 13 unique storm types. With the range of storm probabilities, the range in cost for each unique storm type, and the range in system impact, the 13 unique storm types are represented by 99 different storm events. Table 3-4 provides a summary of the Major Storms Event Database. The table includes the ranges of probabilities, restoration costs, impact to the system, and duration. Each of the 99 storm events are then modeled within the Storm Impact Model described more in the next section.

[8] See Footnote 2

Table 3-4: Storm Event Database

Storm Type No	Scenario Name	Annual Probability	Restoration Costs (Millions)	System Impact (Laterals)	Total Duration (Days)
1	Cat 3+ Direct Hit - Gulf	1.0% - 2.0%	$300 - $1,200	60% - 70%	17.4 - 34.5
2	Cat 1 & 2 Direct Hit – Florida	5% - 8%	$75 - $150	35% - 55%	6.0 - 8.8
3	Cat 1 & 2 Direct Hit – Gulf	2% - 4%	$150 - $300	45% - 60%	8.7 - 12.9
4	TS Direct Hit	16.5%	$25 - $75	12.5% - 31.3%	2.6 - 5.3
5	TD Direct Hit	14.5%	$5 - $15	6.3% - 15.6%	2.0 - 3.6
6	Localized Event Direct Hit	50.0%	$0.5 - $1.5	1.3% - 3.1%	0.3 - 0.6
7	Cat 3+ Partial Hit	3% - 4%	$90 - $180	36% - 48%	6.4 - 9.2
8	Cat 1 & 2 Partial Hit	7.0%	$15 - $90	8.5% - 28%	2.3 - 6.9
9	TS Partial Hit	17% - 18%	$11 - $30	8% - 15%	2.0 - 3.6
10	TD Partial Hit	12% - 15%	$0.4 - $3.0	2% - 3.8%	1.5 - 2.7
11	Cat 3+ Peripheral Hit	2% - 3%	$0.8 - $ 21.4	1.2% - 14.1%	1.0 - 3.0
12	Cat 1 & 2 Peripheral Hit	10% - 11%	$0.6 - $8.6	0.9% - 6.5%	0.9 - 2.3
13	TS Peripheral Hit	11% - 12%	$0.5 - $3.8	0.7% - 3.4%	0.9 - 1.3

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4.0 STORM IMPACT MODEL

The second major component of the Storm Resilience Model is the Storm Impact Model. Whereas the Major Storms Event Database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for each storm stressor, the Storm Impact Model goes a layer deeper and develops the phases of resilience for each potential hardening project on the TEC T&D system for each storm stressor scenario.

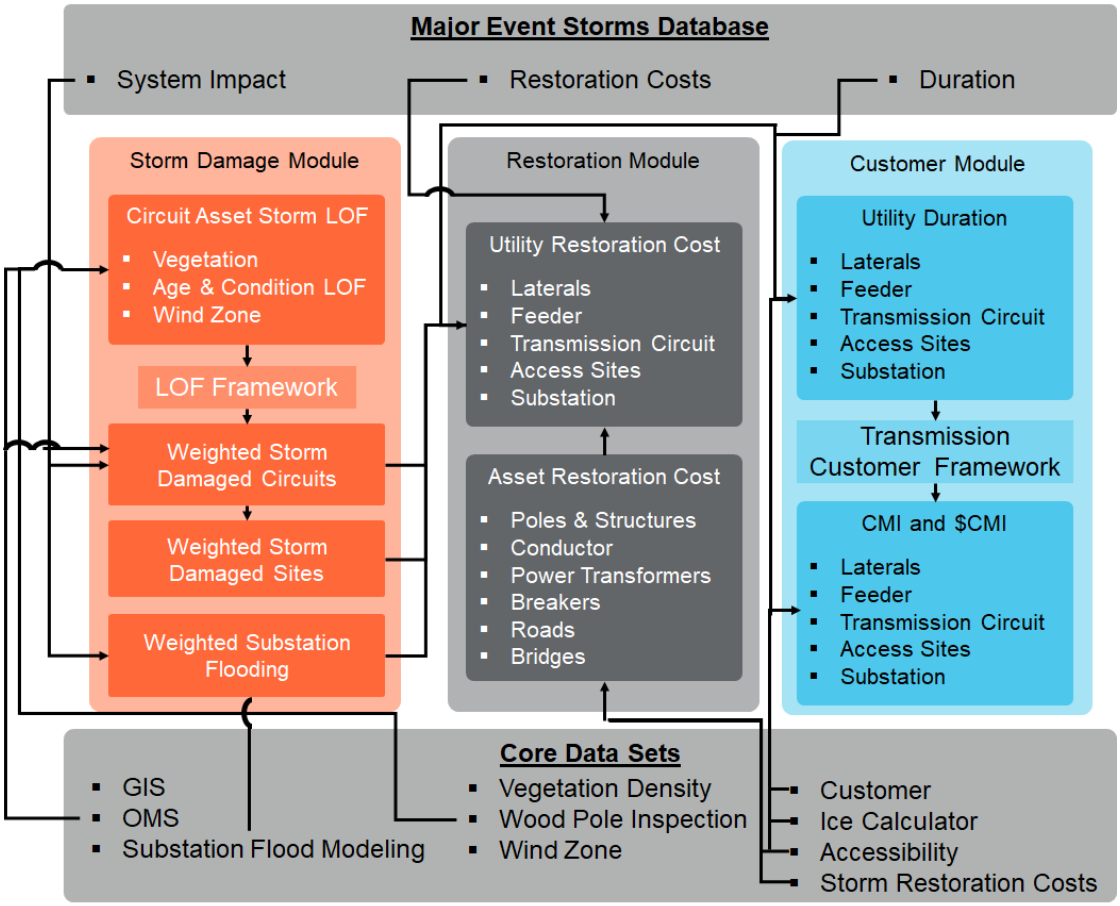
The Storm Impact Model models the impact to the system of any type of major storm event. Specifically, it identifies, from a weighted perspective, the particular laterals, feeders, transmission lines, access sites, and substations that fail for each type of storm in the Major Storms Event Database. The model also estimates the restoration costs associated with the specific sub-system failures and calculates the impact to customers in terms of CMI. Finally, the Storm Impact Model models each storm event for both a Status Quo and Hardened scenario. The Hardened scenario assumes the assets that make up each project have been hardened. The Storm Impact Model then calculates the benefit of each hardening project from a reduced restoration cost and CMI perspective.

The Storm Impact Model utilizes a robust and sophisticated set of data and algorithms to model the benefits of each hardening project for each storm scenario. This section of the report outlines the core data, algorithms, and frameworks that are part of the Storm Impact Model. It outlines a very granular level of analysis of the TEC System. This granular level of data and analysis allows for the Storm Resilience Model to accurately calculate the ratio of resilience benefit to cost resulting in more efficient hardening investment. This also provides confidence that investments are targeted to the portions of the system that provide the most value for customers.

Figure 4-1 provides an overview of the Storm Impact Model architecture. The following sections describe in more detail each of the core modules in more detail.

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Figure 4-1: Storm Impact Model Overview



4.1 Core Data Sets and Algorithms

As discussed above, the resilience-based approach and methodology is data driven. This section outlines the core data sets and base algorithms employed within the Storm Impact Model. TEC's data systems include a connectivity model that allows for the linkage of the three foundational data sets used in the Storm Impact Model – the Geographical Information System (GIS), the Outage Management System (OMS), and Customer Information.

4.1.1 Geographical Information System

The Geographic Information System (GIS) serves as the first of three foundational data sets for the Storm Impact Model. The GIS provides the list of assets in TEC's system and how they are connected to each other. Since the resilience-based approach is fundamentally an asset management bottom-up

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based methodology, it starts with the asset data, then rolls all the assets up to projects, and all projects up to programs, and finally the programs up to the Storm Protection Plan.

In alignment with this methodology, TEC utilized the connectivity in their GIS model to link each distribution voltage asset up to a lateral (fuse protection device) or feeder (breaker or recloser protection device). This provides a granular evaluation of the distribution system that allows projects to be created to target only portions of a circuit for resilience investment. Through this approach, TEC and 1898 & Co. were able to use the asset level information from Table 4-1 and convert it to the project level summaries in Table 4-2. It is important to note that each asset in Table 4-1 is tied to one of the projects listed in Table 4-2, which provides a bottom-up analysis.

Table 4-1: TEC Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**668**
Feeder Poles	[count]	58,700
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,200
Lateral OH Primary	[miles]	3,800
Transmission Circuits	**[count]**	**207**
Wood Poles	[count]	5,000
Steel / Concrete / Lattice Structures	[count]	20,400
Conductor	[miles]	1,300
Substations	[count]	**255**

Table 4-2: Projects Created from TEC Data Systems

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	916
Total	19,666

4.1.2 Outage Management System

The second foundational data set is the OMS. The OMS includes detailed outage information by cause code for each protection device over the last 19 years. The Storm Impact Model utilized this information to understand the historical storm related outages for the various distribution laterals and feeders on the system to include Major Event Days (MED), vegetation, lightening, and storm-based outages. The

OMS served as the link between customer class information and the GIS to provide the Storm Impact Model with the information necessary to understand how many customers and what type of customers would be without service for each project. The OMS data also served as the foundation for calculating benefits for feeder automation projects. This is discussed in more detail in Section 5.4.

4.1.3 Customer Type Data

TEC provided customer count and type information that featured connectivity to the GIS and OMS. This allowed the Storm Impact Model to directly link the number and type of customers impacted to each project and the project's assets. For example, the Storm Impact Model 'knows' that if pole 'Y' fails, fuse '1' will operate causing XX customers to be without service. The model also knows what type of customers are served by each asset; residential, small or large commercial, small or large industrial, and priority customers. This customer information is included for every distribution asset in TEC system. The customer information is used within the Storm Impact Model to calculate the CMI (customers affected * outage duration) for each storm for each lateral or feeder project. Table 4-3 below shows the count of customers by class from TEC's service territory that have been linked to assets in the Storm Impact Model.

Table 4-3: Customer Counts by Type

Customer Type	Customer Count
Residential	695,000
Small Commercial and Industrial	71,100
Large Commercial and Industrial	16,300
Total	782,400

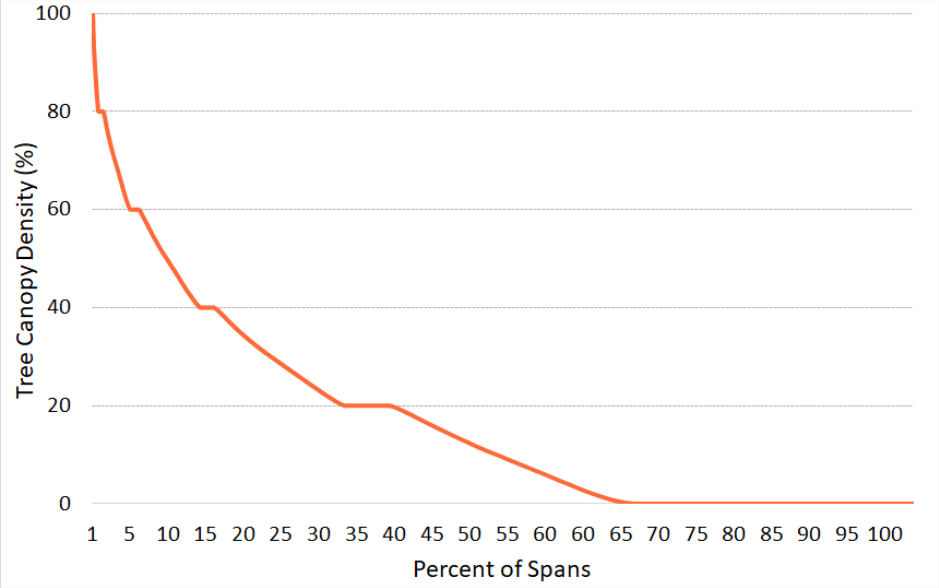
4.1.4 Vegetation Density Algorithm

The vegetation density for each overhead conductor is a core data set for identifying and prioritizing resilience investment for the circuit assets since vegetation blowing into conductor is the primary failure mode for major storm event for TEC. The Storm Impact Model calculates the vegetation density around each transmission and distribution overhead conductor. The Storm Impact Model utilizes tree canopy data to calculate the percentage of vegetation for 100 feet by 100 feet grids across the entire TEC system. The 100 square foot grid size is indicative of the vegetation density on the system from a major storm perspective. For each span of conductor (approximately 240,000) a vegetation density is assigned based on the grid the conductor goes through. This information is used within the LOF framework to identify the portions of the system mostly likely to have an outage for each type of storm.

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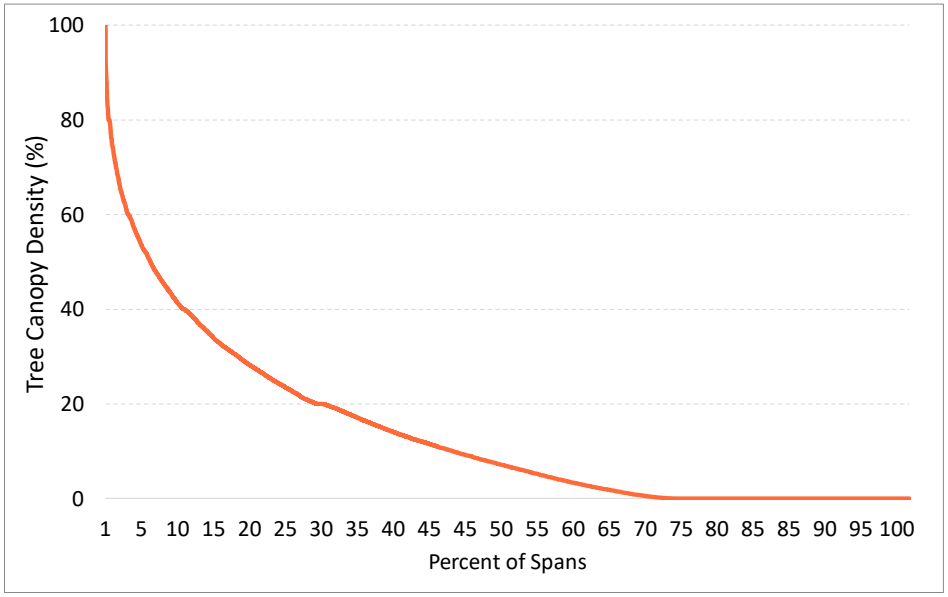
Figure 4-2 and Figure 4-3 show the range of vegetation density for OH Primary and Transmission Conductor, respectively. The figures rank the conductors from highest to lowest level of vegetation density. As shown in the figures, approximately 30 to 35 percent of the conductor spans (not weighted by length) for OH Primary and Transmission Conductor have near zero tree canopy coverage, while approximately 65 to 70 percent have some level of coverage all the way up to 100 percent coverage.

Figure 4-2: Vegetation Density on TEC Primary Conductor



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Figure 4-3: Vegetation Density on TEC Transmission Conductor

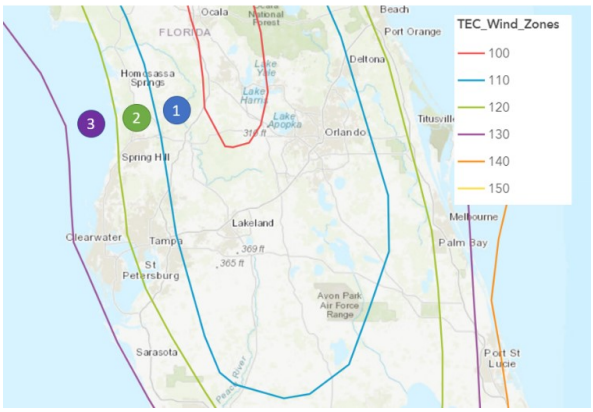


4.1.5 Wood Pole Inspection Data

A compromised, or semi-comprised, pole will fail at lower dynamic load levels then poles with their original design strength. The Storm Impact Model utilizes wood pole inspection data within 1898 & Co.'s asset health algorithm to calculate an Asset Health Index (AHI) and 'effective' age for each pole. Section 4.2.2 outlines the approach for using the 'effective' age for assets to calculate the age and condition based LOF.

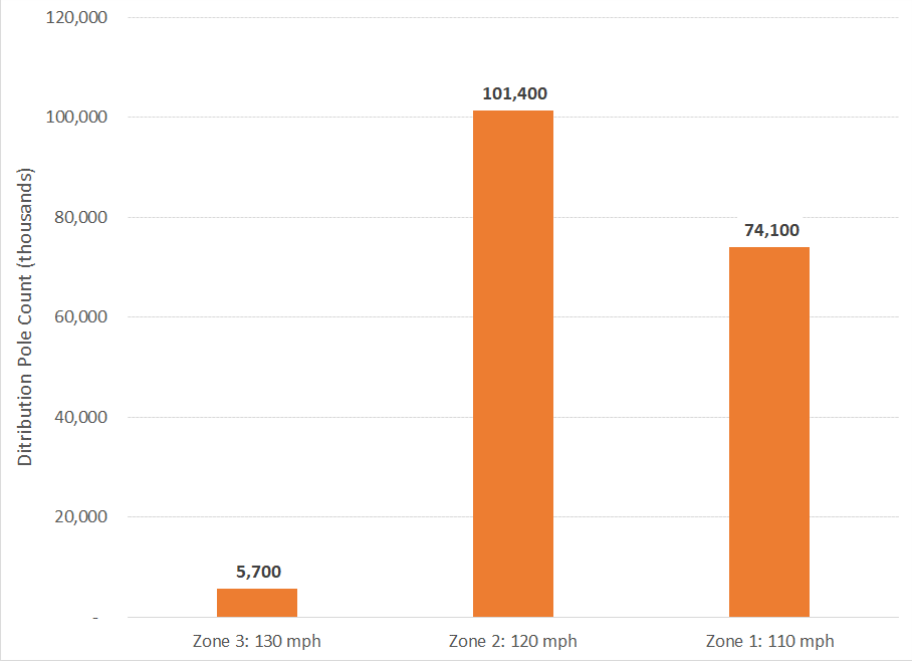
4.1.6 Wind Zone

A third driver of storm-based failure is the asset's location with respect to wind speeds. Wind zones have been created across the United States for infrastructure design purposes. The National Electric Safety Code (NESC) provides wind and ice loading zones. The zones show that wind speeds are typically are higher closer to the coast and lower the further inland as shown in the adjacent figure. The Storm Impact Model utilizes the provided wind zone data from the public records



and the asset geospatial location from GIS to designate the appropriate wind zone. Figure 4-4 shows distribution of assets within each wind zone. As shown in the figure, most of the poles are in the 120 mph and 110 mph zones, while a smaller percentage are in the 130 mph zone near the coast.

Figure 4-4: Pole Wind Zone Distribution



4.1.7 Accessibility

The accessibility of an asset has a tremendous impact on the duration of the outage and the cost to restore that part of the system. Rear lot poles take much longer to restore and cost more to restore than front lot poles. To take differences in accessibility into account, the Storm Impact Model performs a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access, others were designated as in the deep right-of-way (ROW). This designation was used to calculate restoration and hardening project costs in the Storm Impact Model. Approximately 60 percent of the T&D system has some kind of road access while the remainder, approximately 40 percent, is in the deep right-of-way.

4.1.8 ICE Calculator

To monetize the cost of a storm outage, the Storm Impact Model and Resilience Benefit Calculation utilize the ICE Calculator. The ICE Calculator is an electric reliability planning tool developed by Freeman,

Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (DOE).

The Storm Impact Model includes the estimated storm interruption costs for residential, small commercial and industrial (C&I), and large C&I customers. The calculator was extrapolated for the longer outage durations from storm outages. The extrapolation includes diminishing costs as the storm duration extends. These estimates for outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level. The avoided monetized CMI and restoration cost benefit are used for prioritization of projects.

4.1.9 Substation Flood Modeling

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH models perform simulations to estimate surge heights above ground elevation for various storm types. The simulations are based on historical, hypothetical, and predicted hurricanes. The model uses a set of physics equations applied to the specific location shoreline, Tampa in this case, incorporating the unique bay and river configurations, water depths, bridges, roads, levees and other physical features to establish surge height. These results are simulated several thousand times to develop the Maximum of the Maximum Envelope of Water, the worst-case scenario for each storm category. The SLOSH model results were overlaid with the location of TEC's 255 substations to estimate the height of above the ground elevation for storm surge. The SLOSH model identified 59 substations with flooding risk depending on the hurricane category.

4.2 Weighted Storm Likelihood of Failure Module

The Weighted Storm LOF Module of the Storm Impact Model identifies the parts of the system that are likely to fail given the specific storm loaded from the Major Storms Event Database. The module is grounded in the primary failure mode of the asset base; storm surge and associated flooding for substations and wind, asset condition, and vegetation for circuit assets.

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4.2.1 Substation Storm Likelihood of Failure

The main driver of substation failures during major storm events is flooding. The Major Storms Event Database designates the number of substations expected to have minor and major flooding for each of the 99 storm scenarios. Only the storm scenarios with hurricanes coming from the Gulf of Mexico provide the necessary condition for storm surge that would cause substation flooding.

To identify which substations would be the likely to experience flooding, the Storm Impact Model uses the substation flood modeling described in Section 4.1.9. This model provides the estimated feet of flooding above site elevation assuming the maximum of maximum approach, a worst of the worst-case scenario. Because of this extreme worst-case scenario, the results could not be used for a typical hurricane category to hit the TEC service territory. The flood modeling has flood height data for all 5 hurricane category types. The Storm Impact Model uses the flooding height values as likelihood scores to identify the substation Probability of Failure (POF) for each storm event in the Major Storms Event Database.

4.2.2 Circuits Storm Likelihood of Failure

The main driver of circuit failures during storms is wind blowing vegetation (and other debris) into conductor. The conductor is weighted down. The additional weight, when combined with the wind loading, causes the structures holding up the conductor to fail. Typically, the vegetation touching the conductor triggers the protection device to operate, however, the enhanced loading on the poles causes asset failures that are costly to repair both in terms of restoration costs and in CMI. The storm LOF of an overhead distribution asset is a function of the vegetation around it, the age and condition of the asset, and the applicable wind zone (coastal zones see higher wind speeds).

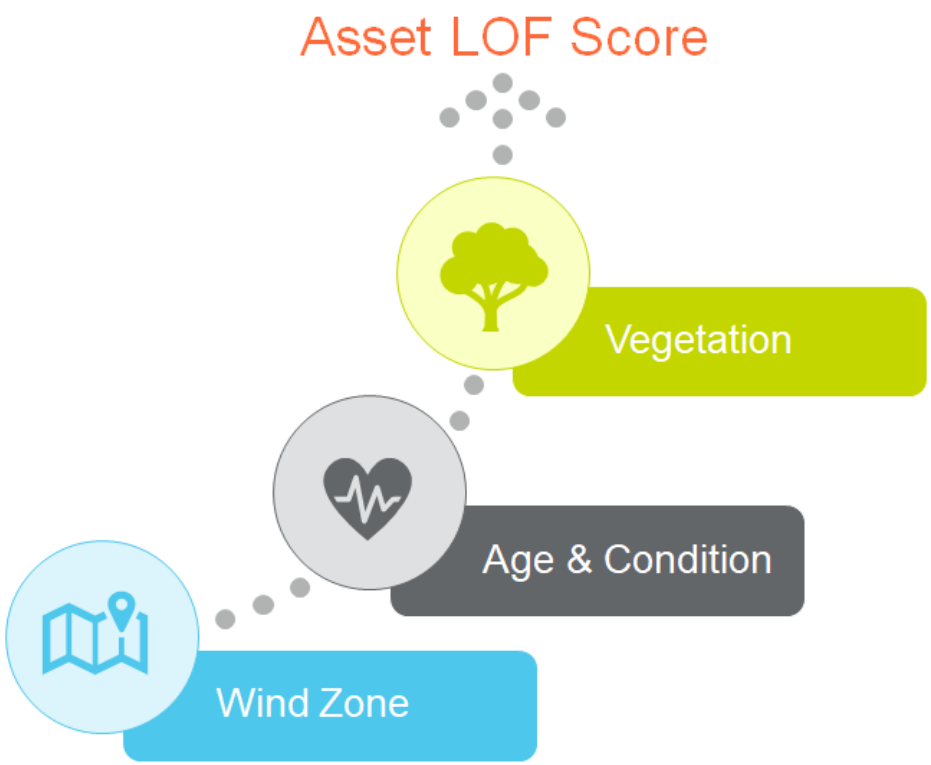
Figure 4-5 depicts the framework used to calculate the storm LOF score for each circuit asset on TEC's T&D system. Assets included within the framework are: wood poles, steel poles, concrete poles, lattice towers, overhead primary, and overhead transmission conductor. The framework does not use weightings, rather it is normalized across each of the scoring criteria.

For the vegetation LOF scores, the Storm Impact Model uses the vegetation density of each overhead primary and transmission conductor normalized for length. Section 4.1.4 outlines the approach to estimate the vegetation density for approximately 240,000 primary and transmission conductors. Each primary and transmission conductor is one span from structure to structure. The vegetation density,

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normalized for length, is used in the LOF framework to calculate an LOF score for vegetation. Overall, the vegetation score contributes on average 60 to 80 percent of system LOF depending on the storm scenario.

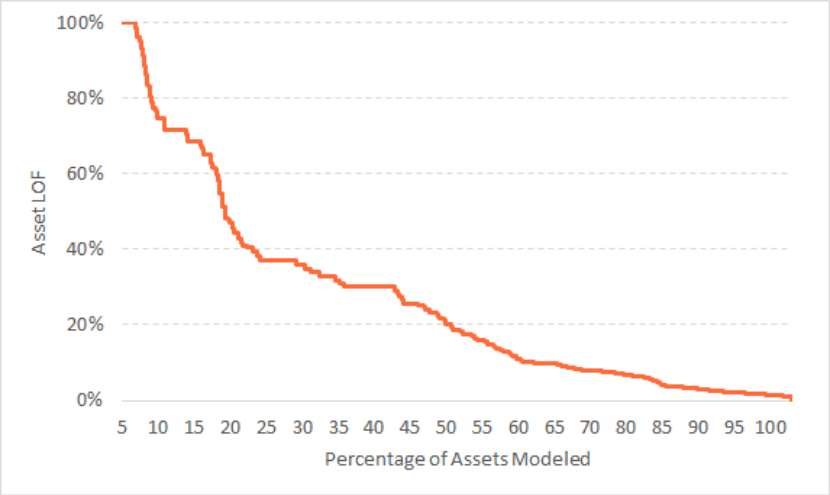
Figure 4-5: Storm LOF Framework for Circuit Assets



The Storm Impact Model utilizes 1898 & Co.'s asset management solution, Capital Asset Planning Solution (CAPS), to estimate the age and condition based LOF for each wood pole, metal structure, overhead primary, and transmission conductor. 1898 & Co.'s CAPS utilizes industry standard survivor curves with an asset class expected average service life and the asset's 'effective' age (or calendar age if condition data is not available) to estimate the age and condition based LOF over the next 10 years. Condition data for wood poles was used to factor in any rot or impacts to the pole's ground-line circumference. Section 4.1.5 outlines the wood pole inspection data used in the 'effective' age calculations.

Figure 4-6 shows the age and condition LOF distribution of the T&D infrastructure asset base. The age and condition based LOF scores were used in the storm LOF framework to calculate storm LOF scores for each asset. Overall, the age and condition score contribute on average 20 to 30 percent of system LOF depending on the storm scenario.

Figure 4-6: Age & Condition LOF Distribution



The wind zone criteria use the wind zone designation data from Section 4.1.6 inside the asset LOF framework to develop the LOF scores. Overall, the wind zone contributes on average 5 to 10 percent of system LOF depending on the storm scenario.

The Storm Impact Model uses the sum of the three criteria (vegetation, age & condition, and wind zone) to calculate the total storm LOF for each asset. The assets are then totaled up to the project level, providing a granular understanding of the LOF for each project. The Storm Impact Model uses the storm LOF scores to identify the circuit project POF for each storm event in the Major Storms Event Database.

4.2.3 Site Access Storm Likelihood of Failure

The site access dataset includes a hierarchy of the impacted circuits. Using this hierarchy, each site access LOF equals the total of the circuits it provides access to. Section 4.2.2, above, provides the details on how the circuit LOF is calculated.

4.3 Project & Asset Reactive Storm Restoration

The Storm Impact Model estimates the cost to repair assets from a storm-based failure. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles,

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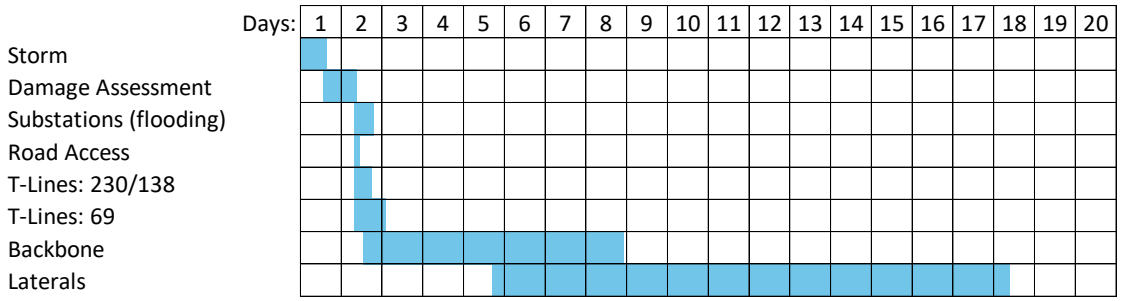
overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were based on storm restoration costs multipliers above planned replacement costs. The multipliers were in the 1.4 to 4.0 range. These multipliers were developed by TEC and 1898 & Co. collaboratively. They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms. Substation restoration costs include storm costs for minor and major flooding events. For minor flooding events, the substation equipment can be used in the short term to restore power flow after cleaning, but the equipment needs to be replaced within 1 year. For major flooding, the substation equipment cannot be restored and must all be replaced. Restoration costs for site access projects were developed by TEC and provided to 1898 & Co.

For each storm event, the restoration costs at the asset level are aggregated up the project level and then weighted based on the project LOF (Section 4.2) and the overall restoration costs for the storm event outlined in the Major Event Storms Database.

4.4 Duration and Customer Impact

The Storm Impact Model calculates the duration to restore each project in the Status Quo Scenario. The assumptions for major asset class outage duration are outlined in the Major Event Storms Database. Figure 4-7 provides an example duration profile for the Category 3 and above storm event.

Figure 4-7: Example Storm Duration Profile



The project specific duration is based on percent complete vs percent time curves for each major asset class. The projects are ranked by metrics that are similar to those TEC uses to prioritize storm restoration activity, such as priority customers. Specific project durations are calculated based on completion vs time curves. For example, using the example from the figure above, a lateral project may have a relatively high priority (i.e. customer count is high with more critical customers). That lateral

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would be restored by day 7 of the profile above. However, the lowest ranked laterals will have project durations in the 16 to 17-day range.

The project duration is then multiplied by the number of affected customers for each project (see Section 4.1.3) to calculate the CMI for each project. It should be noted that the Storm Impact Model assumes feeder automation has been installed on each circuit so that the affected number of customers is 400, the target for each hardening protection zone. This is a conservative assumption so that no double counting of benefits occurs.

Some of the storm scenarios include significant outages to the transmission system. The percentage of the system impacted is so high that the designed resilience (looping) of the system is lost for a short period of time, which in turn causes mass customer outages across the system from the transmission system. The Storm Impact Model allocates customer outages from these events to the various parts of the TEC transmission system based on transmission system operating capacity and overall importance to the Bulk Electric System (BES).

Finally, the CMI for each project for each storm event is monetized using the ICE Calculator. Section 4.1.8 provides additional detail on the ICE Calculator. The monetization is performed for each type of customer; residential, small C&I, large C&I, and the various priority customers. The monetization of CMI is calculated for project prioritization purposes as discussed below in Section 5.0.

4.5 'Status Quo' and Hardening Scenarios

The Storm Impact Model calculates the storm restoration costs and CMI for the 'Status Quo' and Hardening Scenarios for each project by each of the 99 storm events. The delta between the two scenarios is the benefit for each project. This is calculated for each storm event based on the change to the core assumptions (vegetation density, age & condition, wind zone, flood level, restoration costs, duration, and customers impacted) for each project.

The output from the Storm Impact Model is a project by project probability-weighted estimate of annual storm restoration costs, annual CMI, and annual monetized CMI for both the 'Status Quo' and Hardened Scenarios for all 99 major storm scenarios. The following section describes the methodology utilized to model all 99 major storms and calculate the resilience benefit of each project.

5.0 RESILIENCE NET BENEFIT CALCULATION MODULE

The Resilience Benefit Calculation Module of the Storm Resilience Model uses the annual benefit results of the Storm Impact Model and the estimated project costs to calculate the net benefits for each project. Since the benefits for each project are dependent on the type and frequency of major storm activity, the Resilience Benefit Module utilizes stochastic modeling, or Monte Carlo Simulation, to randomly select a thousand future worlds of major storm events to calculate the range of both 'Status Quo' and Hardened restoration costs and CMI. The benefit calculation is performed over a 50-year time horizon, matching the expected life of hardening projects.

The feeder automation hardening project resilience benefit calculation employs a different methodology given the nature of the project and the data available to calculate benefits. The Outage Management System (OMS) includes 19 years of historical data. The resilience benefit is based on the expected decrease in impacted customers if the automation had been in place.

The following sections provide additional detail on the project costs, Monte Carlo Simulation, and feeder automation.

5.1 Economic Assumptions

The resilience net benefit calculation includes the following economic assumptions:

- Period: 50 years – most of the hardening infrastructure will have an average service life of 50 or more years
- Escalation Rate: 2 percent
- Discount Rate: 6 percent

5.2 Project Cost

Project costs were estimated for the over 20,000 projects in the Storm Resilience Model. Some of the project costs were provided by TEC while others were estimated using the data within the Storm Resilience Model to estimate scope (asset counts and lengths) that was then multiplied by unit cost estimates to calculate the project costs. The following sub-sections outline the approach to calculate project costs for each of the programs.

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5.2.1 Distribution Lateral Undergrounding Project Costs

For each project, the GIS (see Section 4.1.1) and Accessibility algorithm (see Section 4.1.7) were leveraged to estimate:

- Miles of overhead conductor for 1, 2, and 3 phase laterals
- Number of overhead line transformers, including number of phases, that need to be converted to pad mounted transformers
- Number of meters connected through the secondary via overhead line.

Each of these values creates the scope for each of the projects. TEC provided unit costs estimates, which are multiplied by the scope activity (asset counts and lengths) to calculate the project cost. The unit cost estimates are based on supplier information and previous undergrounding projects.

5.2.2 Transmission Asset Upgrades Project Costs

The Transmission Asset Upgrades program project costs are based on the number of wood poles by class, type (H-Frame vs monopole), and circuit voltage. TEC provided unit cost estimates for each type of pole to be replaced. The project costs equal the number wood poles on the circuit multiplied by the unit replacement costs.

5.2.3 Substation Extreme Weather Hardening Project Costs

The project costs for the Substation Extreme Weather Hardening program are based on the perimeter of each substation multiplied by the unit cost per foot to install storm surge walls. The costs per foot vary by the required height of the wall. The substation wall height is based off the needed height to mitigate the flooding from the SLOSH model results.

5.2.4 Distribution Overhead Feeder Hardening Project Costs

The distribution overhead feeder hardening project costs are based on the number of wood poles that don't meet current design standards for storm hardening and the cost to include automation. TEC provided unit replacement costs based on the accessibility of the pole as well as the average cost to add automation to each circuit.

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5.2.5 Transmission Access Enhancements

TEC provided all the project costs for the Transmission Access Enhancements. The cost estimates were based on the length of the bridge or road. Those lengths were developed using geospatial solutions using TEC's GIS for each problem area.

5.3 Resilience-weighted Life-Cycle Benefit

The benefits of storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type (e.g. Category 1 from the Gulf) has a range of potential probabilities and consequences. For this reason, the Storm Resilience Model employs stochastic modeling, or Monte Carlo Simulation. Monte Carlo Simulation is a random sampling methodology.

In the context of the Storm Resilience Model, the Monte Carlo simulator selects the major storm events to impact the TEC service territory over the next 50 years from the Major Storms Event Database (Section 3.0). That database outlines the 'universe' of storm event types that could impact the TEC service territory. The database includes 13 unique storm types with 99 different storm events when factoring in the range of probabilities and impacts. The database is based on a historical analysis of major storms to come within 150 miles of the TEC service territory over the last 167 years.

Table 5-1 shows the selection of storm events for each storm type for the first 7 iterations and iteration 1,000. The selected 13 storm events for each iteration represent the future world of storms to impact the TEC service territory over the next 50 years. Each storm has a different frequency and impact to the TEC system. The Monte Carlo Simulation is performed over 1,000 iterations creating a 1,000 of these future storm 'worlds'.

Each project's CMI, monetized CMI, and restoration costs are calculated for the 13 storm events for each iteration for both the 'Status Quo' and Hardened Scenarios over a 50-year time horizon. The difference between the 'Status Quo' and Hardened Scenarios is the benefit of the project for that storm event. The sum of the benefits for all 13 storm events for each iteration equals the total benefits for the project. The CMI, monetized CMI, and restoration costs are then weighted by the probability of the storm event to calculate the storm resilience-weighted life-cycle benefit.

Table 5-1: Monte Carlo Simulation Storm Event Selection

Storm Type No	Scenario Name	Storm Event - Iteration								
		1	2	3	4	5	6	7	...	1000
1	Cat 3+ Direct Hit - Gulf	5	6	5	2	3	6	1	...	3
2	Cat 1 & 2 Direct Hit – Florida	13	16	11	11	8	17	12	...	17
3	Cat 1 & 2 Direct Hit – Gulf	20	24	20	19	19	20	23	...	20
4	TS Direct Hit	28	29	29	30	29	29	30	...	29
5	TD Direct Hit	31	32	31	32	33	31	33	...	31
6	Localized Event Direct Hit	36	35	34	35	36	34	35	...	34
7	Cat 3+ Partial Hit	39	39	39	39	40	37	37	...	41
8	Cat 1 & 2 Partial Hit	43	45	46	43	43	48	45	...	43
9	TS Partial Hit	50	52	52	52	50	54	52	...	50
10	TD Partial Hit	62	61	56	58	61	59	59	...	62
11	Cat 3+ Peripheral Hit	74	72	72	72	71	70	72	...	70
12	Cat 1 & 2 Peripheral Hit	82	87	87	76	79	84	81	...	82
13	TS Peripheral Hit	99	92	98	90	92	93	95	...	88

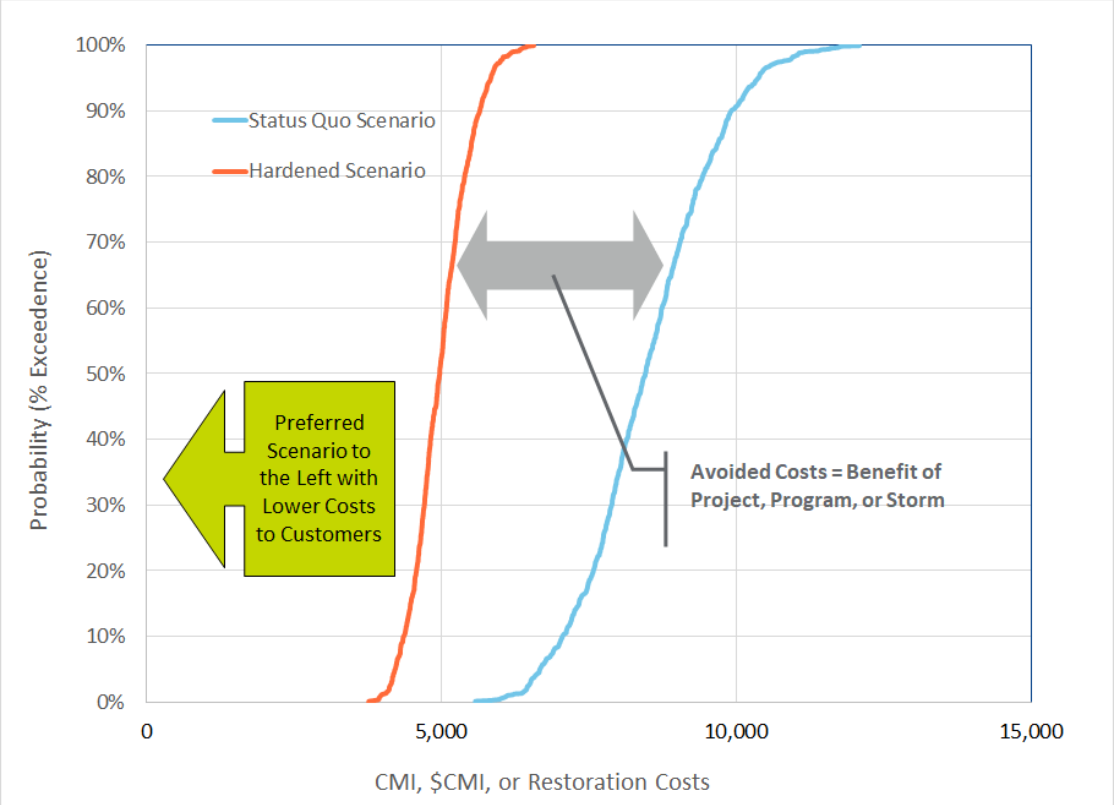
Table 5-2 provides an example calculation of storm resilience weighted CMI, monetized CMI, and restoration costs for both the 'Status Quo' and Hardened Scenarios. Each of the values is weighted by the probability of the event from the storms database over the 50-year time horizon. The monetized CMI and restoration cost show the NPV of the 50-year storm probability adjusted cash flows. The delta between the 'Status Quo' and Hardened scenarios is the benefits of the project for the first iteration. The example shows that the project is not impacted by small or peripheral storms. This calculation is repeated for all 1,000 iterations for the over 20,000 projects in the Storm Resilience Model.

Table 5-2: Project CMI and Restoration Cost Example – Iteration 1

Storm Type No	Scenario Name	Status Quo			Hardened		
		CMI	$CMI	Rest$	CMI	$CMI	Rest$
1	Cat 3+ Direct Hit – Gulf	64,910	$606,664	$132,303	41,947	$392,045	$0
2	Cat 1 & 2 Direct Hit – Florida	26,001	$377,198	$38,694	16,803	$243,757	$0
3	Cat 1 & 2 Direct Hit – Gulf	22,228	$305,395	$38,078	14,364	$197,356	$0
4	TS Direct Hit	26,587	$471,815	$53,821	17,072	$302,952	$43,127
5	TD Direct Hit	9,612	$150,651	$9,619	6,172	$96,733	$7,708
6	Localized Event Direct Hit	1,282	$27,601	$4,858	823	$17,723	$3,893
7	Cat 3+ Partial Hit	5,975	$86,440	$12,779	3,862	$55,860	$0
8	Cat 1 & 2 Partial Hit	3,575	$58,056	$14,771	2,310	$37,517	$0
9	TS Partial Hit	1,077	$27,788	$6,303	691	$17,843	$5,051
10	TD Partial Hit	$0	$0	$0	$0	$0	$0
11	Cat 3+ Peripheral Hit	$0	$0	$0	$0	$0	$0
12	Cat 1 & 2 Peripheral Hit	$0	$0	$0	$0	$0	$0
13	TS Peripheral Hit	$0	$0	$0	$0	$0	$0
	Total	161,246	$2,111,610	$311,225	104,043	$1,361,786	$59,779

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. Figure 5-1 shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios. The resilience benefit of the project, program, or plan is the gap between the S-curves for the top part of the curve. Section 2.4 describes this in further detail.

Figure 5-1: Status Quo and Hardened Results Distribution Example



5.4 Feeder Automation Benefits Calculation

As part of the Storm Protection Plan, TEC intends to include feeder automation to allow for automatic switching during storm events. The design standard is to limit outages to impact a maximum of 400 customers. While many of the other Storm Protection Programs provide resilience benefit by mitigating outages from the beginning, feeder automation projects provide resilience benefit by decreasing the impact of a storm event, the 'pit' of the resilience conceptual model described in Figure 2-2 above.

The resilience benefit for feeder automation was estimated using historical Major Event Day (MED) outage data from the OMS (see Section 4.1.2). TEC has outage records going back 19 years. The analysis assumes that future MED outages for the next 50 years will be similar to the last 19 years.

The outage records document all outages by protection device. The system includes customer relationship information for each protection device to calculate the number of customers impacted if a device operates. The OMS records the start and end times for each outage. The information from the

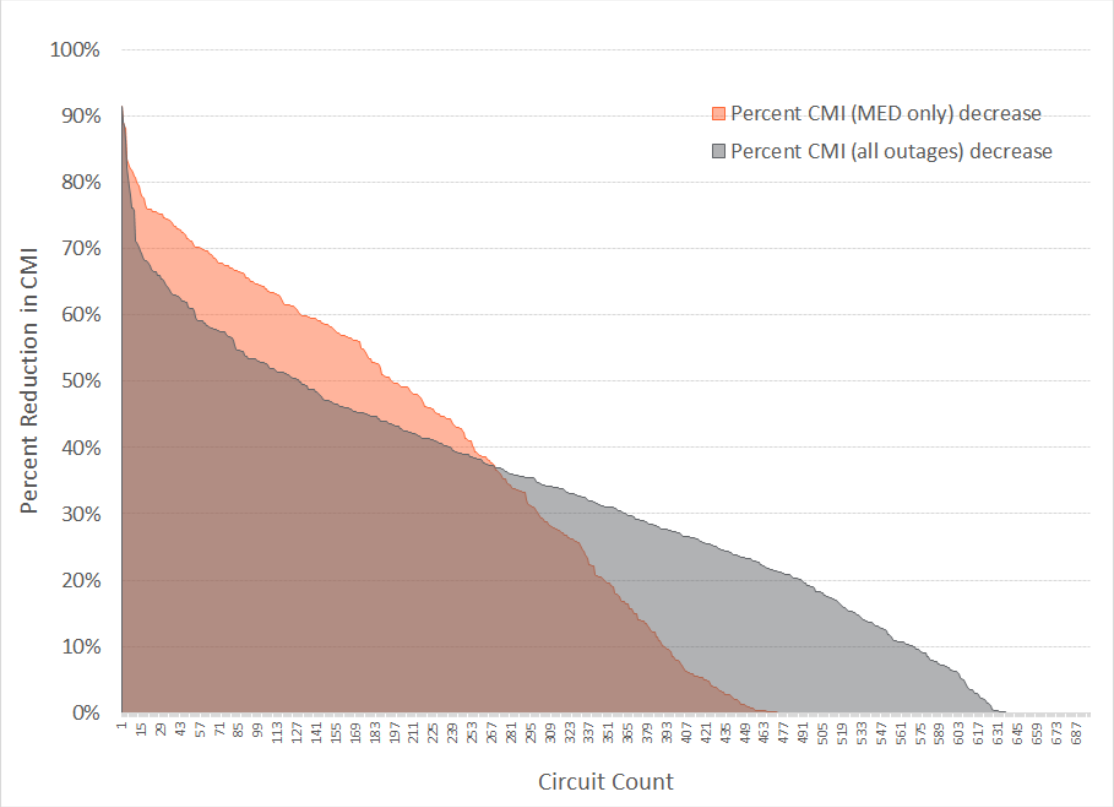
OMS is used to calculate reliability metrics for reporting purposes. The OMS also includes designations for MED, which are days during which a significant part of the system is impacted by a major event. These are typically major storms. MED is often referred to as 'grey-sky' days as opposed to non-MED which is referenced as 'blue-sky' days.

For the resilience benefit calculation, the Storm Resilience Model re-calculates the number of customers impacted by an outage, assuming that feeder automation had been in place. For example, a historical outage may have included a down pole from a storm event, causing the substation breaker to lock out and resulting in a four-hour outage for 1,500 customers, or 360,000 CMI. The Storm Resilience Model re-calculates the outages as 400 customers without power for four hours, or 96,000 CMI. That example provides a reduction in CMI of over 70 percent. The Storm Resilience Model extrapolates the 19 years of benefit calculation to 50 years to match the time horizon of the other projects.

The feeder automation projects include a range of investment types including reclosers, poles, re-conductering, adding tie lines, and substation upgrades to handle the load transfer. TEC provided the itemized costs for feeder automation for projects installed in years 2020 and 2021, and expected average feeder costs for years 2022 through 2029.

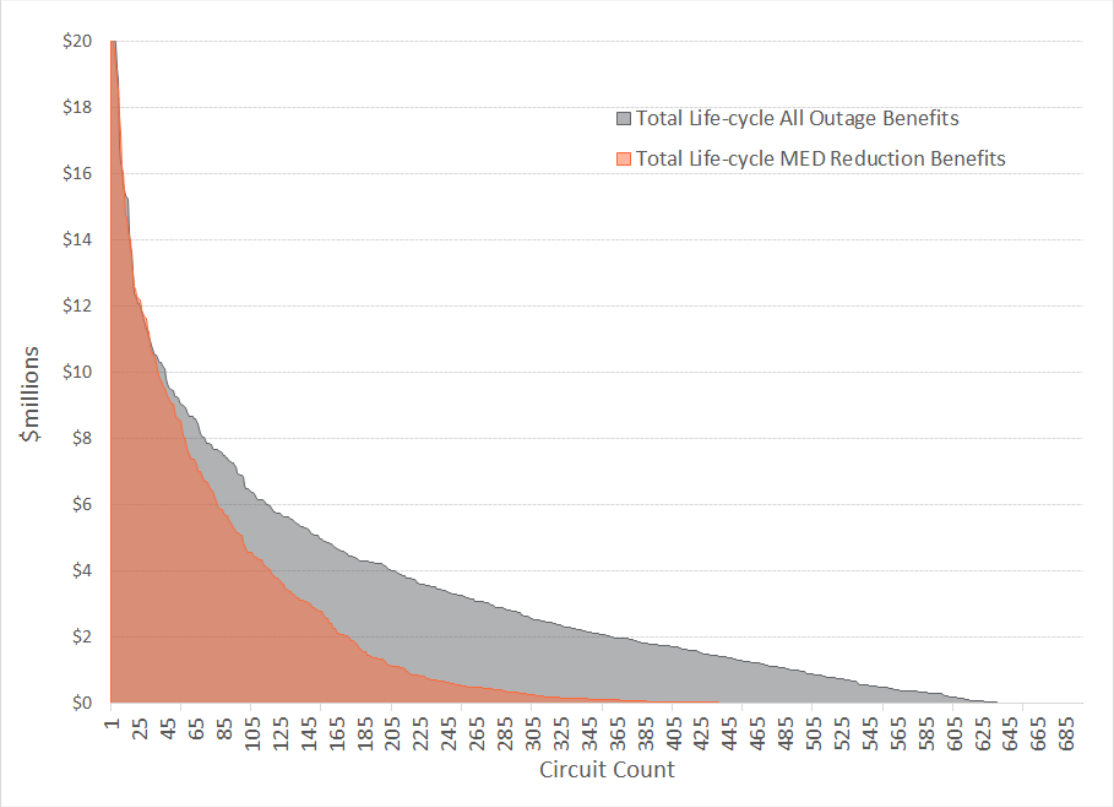
Figure 5-2 shows the percent decrease in CMI using this approach for all circuits. The figure is ranked from highest to lowest from left to right. The figure also includes the benefits to all outages. The figure shows a wide range of decreased CMI percentages with nearly 40 percent of circuits resulting in a 40 percent or more decrease in MED CMI. Additionally, the figure shows that approximately two thirds of the circuits would decrease MED CMI.

Figure 5-2: Automation Hardening Percent CMI Decrease



The resilience benefit calculation also monetized the CMI decrease using the ICE Calculator (Section 4.1.8). Figure 5-3 shows the percent decrease in monetized CMI for each circuit. The CMI was monetized and discounted over the 50-year time horizon to calculate the NPV. The NPV calculation assumed a replacement of the reclosers in year 25; the rest of the feeder automation investment has an expected life of 50 years or more. The monetization and discounted cash flow methodology was performed for project prioritization purposes.

Figure 5-3: Automation Hardening Monetization of CMI Decrease



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6.0 BUDGET OPTIMIZATION AND PROJECT SELECTION

The Storm Resilience Model models consistently models the benefits of all potential hardening projects for an 'apples to apples' comparison. Sections 3.0, 4.0, and 5.0 described the approach and methodology to calculate the resilience benefit for the over 20,000 projects. Resilience benefit values include:

- CMI 50-year Benefit
- Restoration Cost 50-year NPV Benefit
- Life-cycle 50 year NPV gross Benefit (monetized CMI benefit + restoration cost benefit)
- Life-cycle 50 year NPV net Benefit (monetized CMI benefit + restoration cost benefit – project costs)

Each of these values includes a distribution of results from the 1,000 iterations. For ease of understanding and in alignment with the resilience base strategy, the approach focuses on the P50 and above values, specifically considering:

- P50 – Average Storm Future
- P75 – High Storm Future
- P95 – Extreme Storm Future

The following sections discuss the prioritization metric, budget optimization, and approach to developing the Storm Protection Plan.

6.1 Prioritization Metric - Benefit Cost Ratio

With all the projects being evaluated on a consistent basis, they can all be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life-cycle 50 year NPV gross benefit value listed above. The ranking is performed for each of the P-values listed above (P50, P75, and P95) as well as a weighted value.

Performing prioritization for the four benefit cost ratios is important since each project has a different slope in their benefits from P50 to P95. For instance, many of the lateral undergrounding projects have the same benefit at P50 as they do at P95. Alternatively, many of the transmission asset hardening projects are minorly beneficial at P50 but have significant benefits at P75 and even more at P95. TEC and 1898 & Co. settled on a weighting on the three values for the base prioritization metric, however,

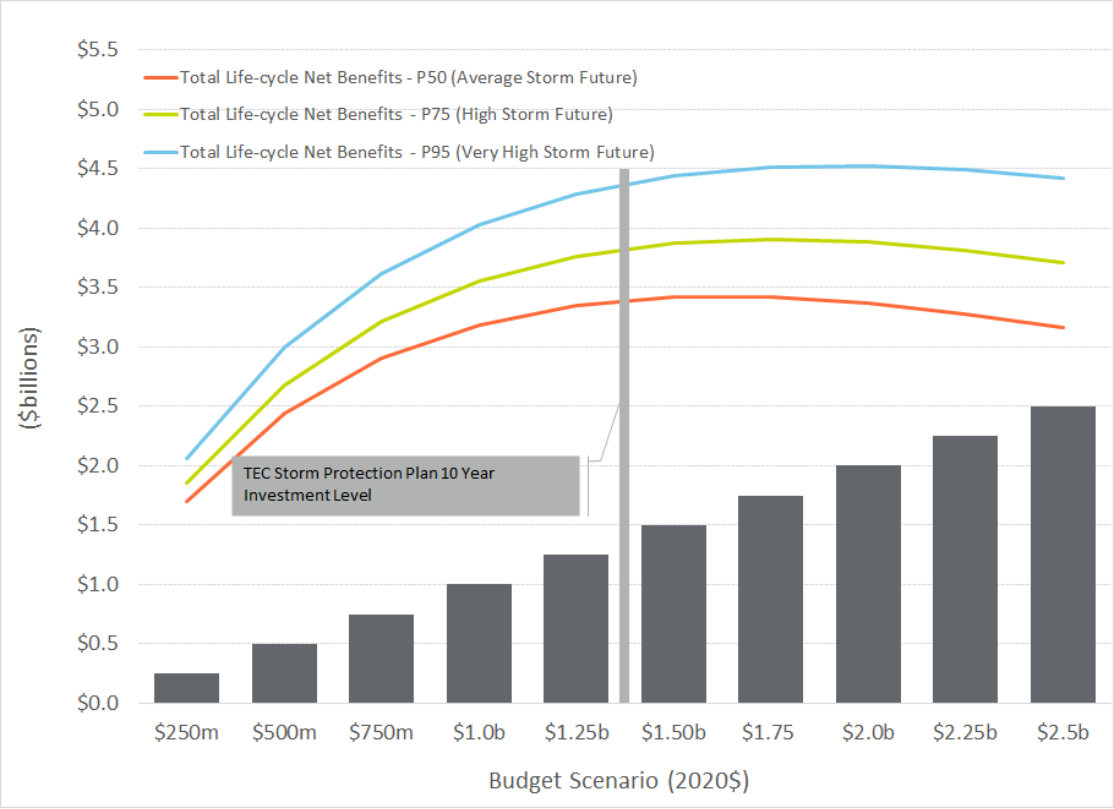
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investment allocations are adjusted for some of the programs where benefits are small at P50 but significant at P75 and P95.

6.2 Budget Optimization

The Storm Resilience Model performs project prioritization across a range of budget levels to identify the appropriate level of resilience investment. The goal is to identify where 'low hanging' resilience investment exists and where the point of diminishing returns occurs. Given the total level of potential investment the budget optimization analysis was performed in $250 million increments up to $2.5 billion. Figure 6-1 shows the results of the budget optimization analysis. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95.

Figure 6-1: Budget Optimization Results



The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2020 dollars for the TEC Storm Protection

Plan. The TEC overall investment level is right before the point of diminishing returns showing that TEC's plan has an appropriate level of investment capturing the hardening projects that provide the most value to customers.

6.3 Storm Protection Plan Project Prioritization

In developing TEC's Storm Protection Plan, TEC and 1898 & Co. used the Storm Resilience Model as a tool for developing the overall budget level and the budget levels for each category. It is important to note that the Storm Resilience Model is only a tool to enable more informed decision making. While the Storm Resilience Model employs a data-driven decision-making approach with robust set of algorithms at a granular asset and project level, it is limited by the availability and quality of assumptions. In developing the TEC Storm Protection plan project identification and schedule, the TEC and 1898 & Co team factored in the following:

- Resilience benefit cost ratio including the weighted, P50, P75, and P95 values.
- Internal and external resources available to execute investment by program and by year.
- Lead time for engineering, procurement, and construction
- Transmission outage and other agency coordination.
- Asset bundling into projects for work efficiencies.
- Project coordination (i.e. project A before project B, project Y and project Z at the same time).

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7.0 RESULTS & CONCLUSIONS

TEC and 1898 & Co. utilized a resilience-based planning approach to identify and prioritize resilience investment in the T&D system. This section presents the costs and benefits of TEC's Storm Protection Plan. Customer benefits are shown in terms of the:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as CMI

7.1 Storm Protection Plan

This section includes the program capital investment and resilience benefit results for TEC's Storm Protection Plan.

7.1.1 Investment Profile

Table 7-1 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.46 billion. Lateral undergrounding makes up most of the total, accounting for 66.8 percent of the total investment. Feeder Hardening is second, accounting for 19.8 percent. Transmission upgrades make up approximately 10.2 percent of the total, with substations and site access making up 2.2 percent and 1.0 percent, respectively. The plan includes a few months of investment in 2020 and a ramp-up period to levelized investment (in real terms) in 2022.

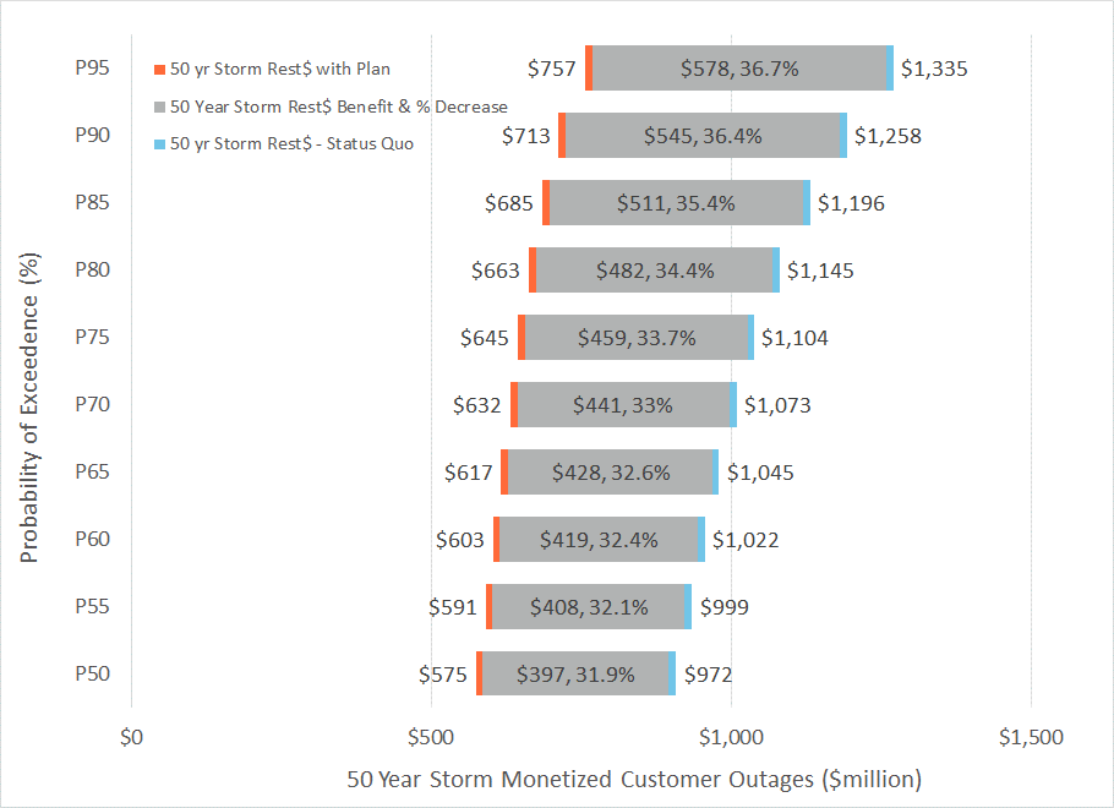
Table 7-1: Storm Protection Plan Investment Profile by Program (Nominal $000)

Year	Lateral Undergrounding	Transmission Asset Upgrades	Substation Hardening	Feeder Hardening	Transmission Site Access	Total
2020	$8,000	$5,600	$0	$6,200	$0	$19,700
2021	$79,500	$15,200	$0	$15,400	$1,400	$111,500
2022	$108,100	$15,000	$0	$29,600	$1,500	$154,200
2023	$101,400	$16,500	$0	$33,400	$1,600	$152,900
2024	$107,000	$11,900	$7,300	$32,500	$1,700	$160,400
2025	$110,800	$19,000	$5,500	$33,200	$1,300	$169,900
2026	$114,000	$17,700	$4,700	$33,800	$400	$170,600
2027	$111,400	$16,300	$6,700	$32,800	$3,300	$170,500
2028	$115,500	$19,600	$5,200	$36,400	$2,000	$178,700
2029	$121,100	$12,100	$2,900	$36,300	$1,700	$174,000
Total	$976,800	$148,900	$32,400	$289,600	$14,800	$1,462,500

7.1.2 Restoration Cost Reduction

Figure 7-1 shows the range in restoration cost reduction at various probability of exceedance levels. As a refresher, the P50 to P65 level represents a future world in which storm frequency and impact are close to average, the P70 to P85 level represents a future world where storms are more frequent and intense, and the P90 and P95 levels represent a future world where storm frequency and impact are all high.

Figure 7-1: Storm Protection Plan Restoration Cost Benefit

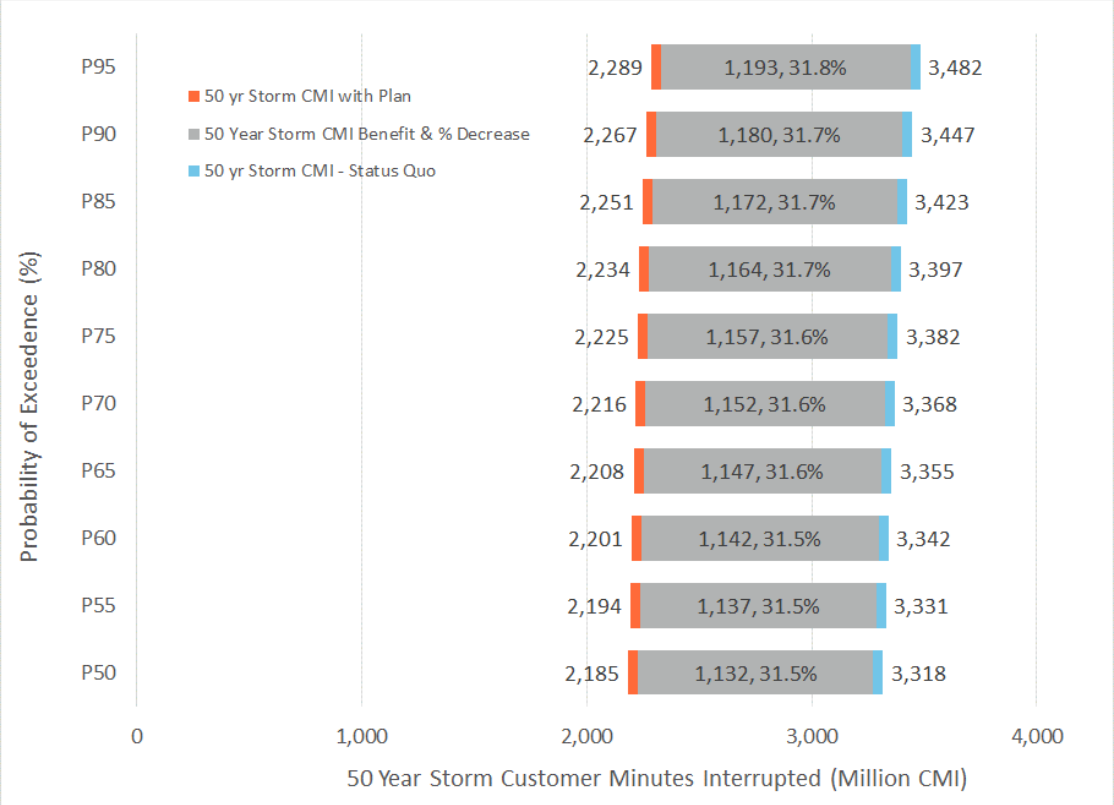


The figure shows that the 50 NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to $580 million. From an NPV perspective, the restoration costs decrease benefit is approximately 36 to 53 percent of the project costs.

7.1.3 Customer Benefit

Figure 7-2 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 32 percent decrease in the storm CMI over the next 50 years.

Figure 7-2: Storm Protection Plan Customer Benefit



7.2 Program Investment Profile Details

Table 7-3, Table 7-4, Table 7-5, and Table 7-6 show annual investment for the five programs evaluated in the Storm Resilience Model. The tables also show the counts associated with the investment level. For Table 7-3 the total count of circuits being worked on each year is shown. Several circuits are worked on over multiple years. The plan includes upgrading assets on 131 different circuits.

Table 7-2: Distribution Lateral Undergrounding Investment Profile

Year 1	Lateral Count	Miles	Nominal Cost ($000)
2020	24	10	$8,000
2021	281	101	$79,500
2022	316	119	$108,100
2023	308	105	$101,400
2024	286	124	$107,000
2025	283	106	$110,800
2026	286	118	$114,000
2027	318	146	$111,400
2028	298	126	$115,500
2029	282	152	$121,100
Total	2,682	1,107	$976,800

Table 7-3: Transmission Asset Upgrades Investment Profile

Year 1	Circuits Worked On	Nominal Cost ($000)
2020	21	$5,600
2021	35	$15,200
2022	28	$15,000
2023	15	$16,500
2024	15	$11,900
2025	6	$19,000
2026	7	$17,700
2027	10	$16,300
2028	13	$19,600
2029	20	$12,100
Total	NA	$148,900

Table 7-4: Substation Extreme Weather Hardening Investment Profile

Year	Count	Nominal Cost ($000)
2020	0	$0
2021	0	$0
2022	0	$0
2023	0	$0
2024	1	$7,300
2025	2	$5,500
2026	2	$4,700
2027	4	$6,700
2028	1	$5,200
2029	1	$2,900
Total	11	$32,400

Table 7-5: Distribution Overhead Feeder Hardening Investment Profile

Year	Feeder Count	Nominal Cost ($000)
2020	5	$6,200
2021	18	$15,400
2022	13	$29,600
2023	41	$33,400
2024	43	$32,500
2025	40	$33,200
2026	45	$33,800
2027	40	$32,800
2028	59	$36,400
2029	53	$36,300
Total	357	$289,600

Table 7-6: Transmission Access Enhancements Investment Profile

Year	Count	Nominal Cost ($000)
2020	0	$0
2021	8	$1,400
2022	6	$1,500
2023	5	$1,600
2024	4	$1,700
2025	4	$1,300
2026	1	$400
2027	3	$3,300
2028	3	$2,000
2029	3	$1,700
Total	37	$14,800

7.3 Program Benefits

Table 7-7 shows the restoration cost and CMI benefit for each of the programs. The ranges include the P50 to P95 values. Figure 7-3 shows each program's percentage of the total benefits compared to the program's percentage of the total capital investment. The figure shows the benefit values for both restoration cost and CMI.

Table 7-7: Program Benefit Levels

Program	Restoration Cost Percent Decrease	Storm CMI Percent Decrease
Distribution Lateral Undergrounding	~33%	~44%
Transmission Asset Upgrades	~90%	~13%
Substation Extreme Weather Hardening	70% to 80%	50% - 65%
Distribution Feeder Hardening	38% to 42%	30%
Transmission Access Enhancements	10%	~74%

Figure 7-3: Program Benefits vs. Capital Investment

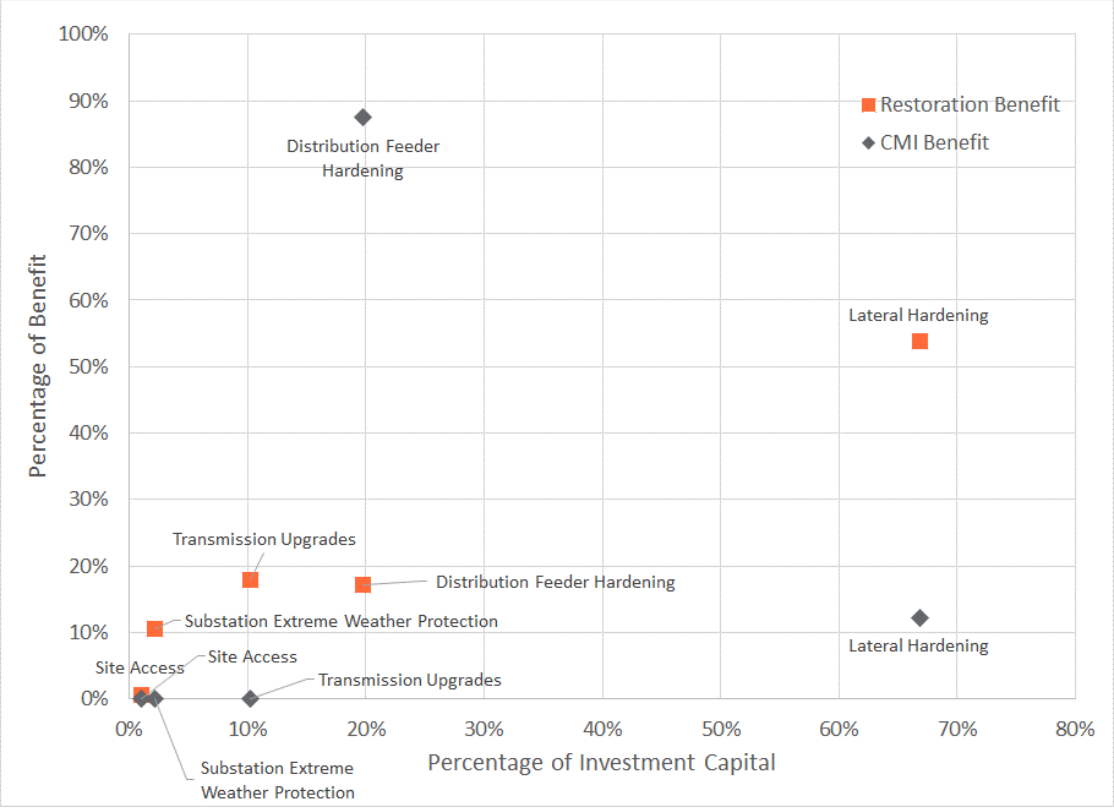


Table 7-7 and Figure 7-3 shows

- Distribution Feeder Hardening and Lateral Undergrounding account for 87 percent of the total capital investment, nearly all the CMI benefit, and approximately 71 percent of the restoration benefit.

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- The Distribution Lateral Undergrounding program decreases the storm related CMI and restoration costs for the asset base by approximately 44 and 33 percent, respectively. Additionally, the program accounts for approximately 67 percent of the total plan's invested capital, approximately 54 percent of the plan's restoration benefit, and approximately 12 percent of the plan's CMI benefit. The low overall CMI reduction relative to the total reduction is because of the high decrease from the Feeder Hardening program, specifically feeder automation.
- The Distribution Feeder Hardening program contributes approximately 87 percent of the CMI benefit of the plan, mainly from feeder automation based on the historical 'grey sky' days.
- While Transmission Assets, Substation, and Access programs achieve fairly high percentages in decreasing CMI, their total contribution to CMI reduction for the plan is low (less than 1 percent).
- Substation Hardening accounts for over 10.5 percent of the restoration benefit of the plan while only accounting for approximately 2.2 percent of the capital investment. The cost to restore flooded substations is extremely high.

7.4 Conclusions

The following include the conclusions of TEC's Storm Protection plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.46 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 6-1) shows the investment level is right before the point of diminishing returns.
- TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 32 to 37 percent. In relation to the plan's capital investment, the restoration costs savings range from 36 to 53 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 32 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.
- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.61 to $0.82 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.

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- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.
- The hardening investment will provide additional 'blue sky' benefits to customers not factored into this report.



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2022 – 2031 Storm Protection Plan
Resilience Benefits Report

Tampa Electric Company

TEC SPP Resilience Benefits Report
Project No. 132540

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
AHI	Asset Health Index
ANL	Argonne National Laboratory
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CMI	Customer Minutes Interrupted
DOE	Department of Energy
FLISR	Fault Location, Isolation, Service Restoration
GIS	Geographic Information System
ICE	Interruption Cost Estimator
IEEE	Institute of Electrical and Electronics Engineers
LOF	Likelihood of Failure
MED	Major Event Day
NARCU	National Association of Regulatory Utility Commissioners
NASC	National Electric Safety Code
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
OMS	Outage Management System
PNNL	Pacific Northwest National Laboratory's
POF	Probability of Failure
ROW	Right-of-Way

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Abbreviation	Term/Phrase/Name
SIM	Storm Impact Model
SLOSH	Sea, Land, and Overland Surges from Hurricanes
SPP	Storm Protection Plan
T&D	Transmission and Distribution
TEC	Tampa Electric Company

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1.0 EXECUTIVE SUMMARY

Tampa Electric Company (TEC) engaged the services of 1898 & Co, the advisory and technology consulting arm of Burns & McDonnell, to assist with the development of the 2022 to 2031 10-year Storm Protection Plan required by Florida Statute 366.96, also known as Senate Bill 796. In collaboration, TEC and 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and prioritize investment in the Transmission and Distribution (T&D) system utilizing a Storm Resilience Model. The Storm Resilience Model evaluates each hardening project's ability to reduce the magnitude and/or duration of disruptive storm events. Key objectives for the Storm Resilience Model are:

1. Calculate the customer benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level that maximizes customers benefit while not exceeding TEC technical execution constraints

While the resilience benefit is significant and is the focus of this report, it is not the only benefit of TEC's Storm Protection Plan. Additional benefits are described and quantified elsewhere in TEC's Plan. The Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit of hardening projects in terms of the range of reduced restoration costs and Customer Minutes Interrupted (CMI). The hardening projects provide resilience benefit from several perspectives. Some of the hardening projects eliminate storm-based outages all together, some reduce the number of customers impacted (CI), and others decrease the duration of storm-related outages. This report shows only the reduction in CMI, which accounts for both types of benefits. However, there is a strong relationship between reduction in CMI and reduction in CI.

Resilience-based prioritization facilitates the identification of the hardening projects that provide the most benefit. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers will get the most value for the level of investment.

This report outlines project prioritization and benefits calculations for the following TEC storm hardening programs:

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- Distribution Lateral Undergrounding
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

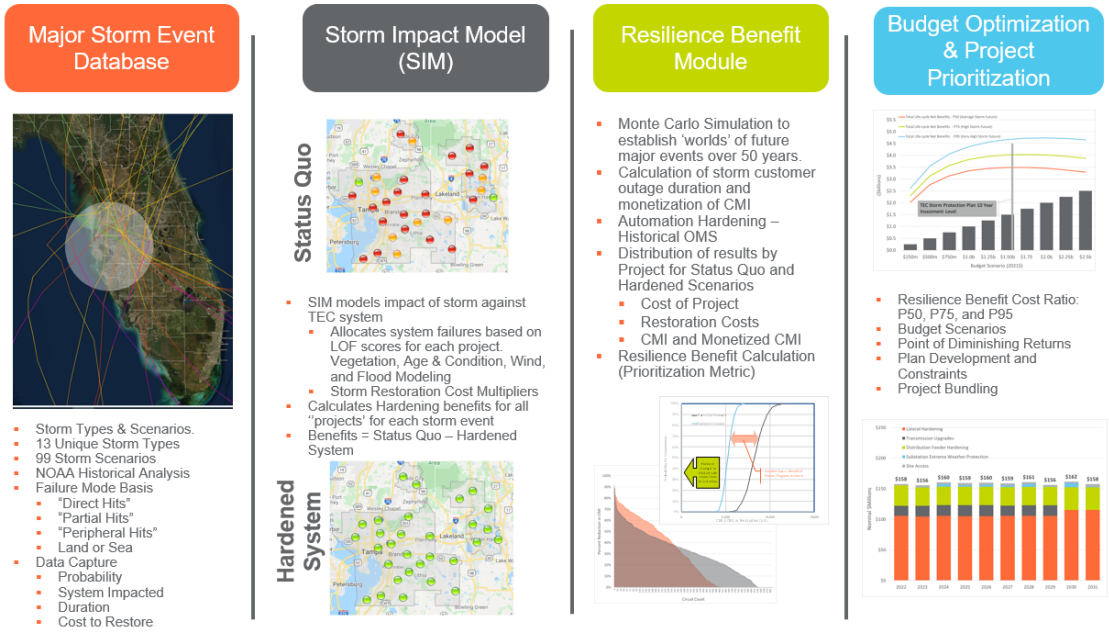
The other programs within TEC's Storm Protection Plan, Vegetation Management, Infrastructure Inspections, and Distribution Pole Replacements, are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's Storm Protection Plan. Similarly, their benefits are described in other portions of TEC's Storm Protection Plan.

1.1 Resilience Based Planning Approach

Figure 1-1 provides an overview of the Storm Resilience Model. The model employs a resilience-based planning approach to calculate the benefits of reducing storm restoration costs, CI, and CMI. Each of the different components are reviewed in further detail in Sections 3.0, 4.0, 5.0, and 6.0.

The Major Storm Events Database contains 13 unique storm types with a range of probabilities and impacts to create a total database of 99 different unique storm scenarios. The storm scenarios range from a Category 3 or greater direct hit from the Gulf of Mexico to a Category 1 or 2 partial hit over Florida, to a tropical storm. Section 3.0 provides additional details on the 99 different storm scenarios.

Figure 1-1: Storm Resilience Model Overview



Each storm scenario is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Likelihood of Failure (LOF) is based on the vegetation density around each conductor asset, the age and condition of the asset base, and the applicable wind zone for the asset's location. The Resilience Model is comprehensive in that it evaluates nearly all TEC's T&D system. Table 1-1 provides an overview of the potential project count for each of the programs.

Table 1-1: Potential Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	12,310
Transmission Asset Upgrades	107
Substation Extreme Weather Hardening	9
Distribution Overhead Feeder Hardening	1,385
Transmission Access Enhancements	44
Total	13,855

The Storm Impact Model also estimates the restoration costs and CMI for each of the projects in Table 1-1 above for each storm scenario. For purposes of this report, the term "project" refers to a collection of assets. Assets are typically organized from a customer impact perspective, see Section 2.2. Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is

hardened per TEC's hardening standards. The CMI benefit is monetized using the DOE's Interruption Cost Estimator (ICE) for project prioritization purposes.

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future storm worlds and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest resilience benefit cost ratio. It also performs a budget optimization over a range of budget levels to identify the point of diminishing returns.

The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates TEC's technical and operational constraints in scheduling the projects such as contractor capacity and scheduling planned transmission outages. Using the Resilience Benefit Calculation and Project Scheduling and Budget Optimization model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

1.2 Key Updates to Storm Resilience Model from 2020 to 2029 SPP to 2022 to 2031 SPP

The following are the key updates from the 2020-2029 to the 2022-2031 Storm Resilience Model:

1. General – these updates include shifting of the time horizon, adding another year of storms to the historical analysis, and accounting for completed projects.
2. Capital Cost Assumptions – based on actual completed projects and communicated increases in commodity prices the cost assumptions for all project types were adjusted.
3. Substation Projects Development – TEC completed a technical evaluation of substation hardening alternatives since the 2020-2029 Storm Protection Plan filing. The results of that evaluation, including specific substation hardening activities and their cost were included in the model.

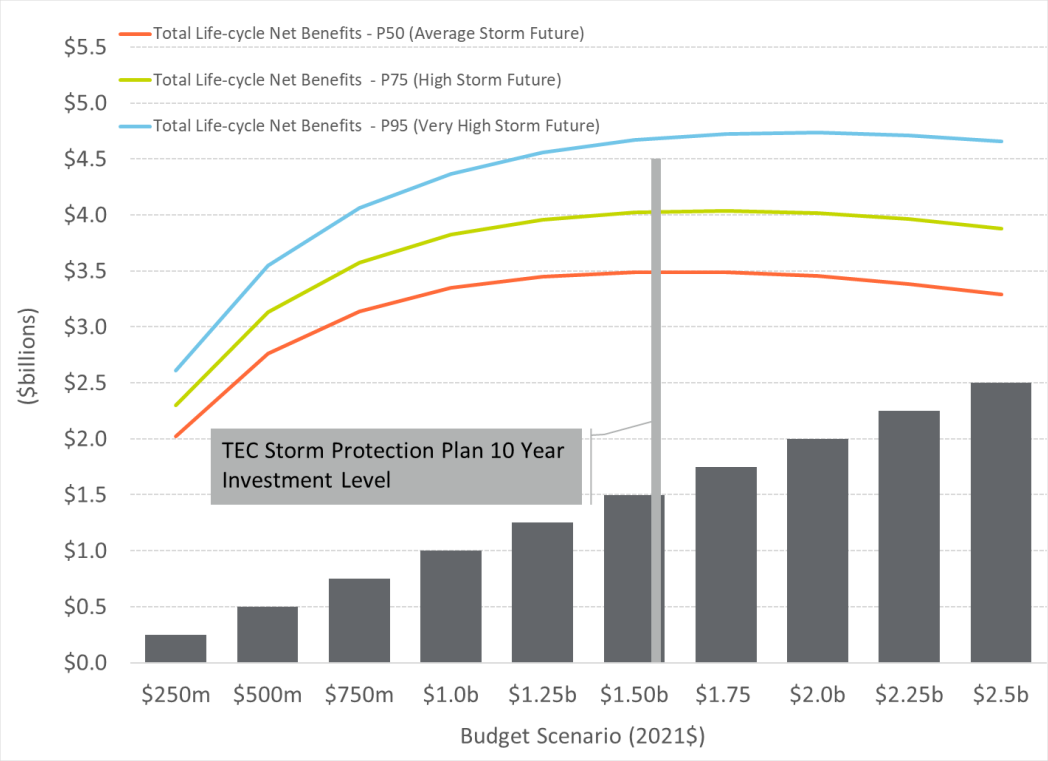
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4. Site Access Project Development – TEC performed additional evaluation of transmission site access and updated the projects and associated costs.
5. Automation Hardening Capital Costs – 1898 & Co. performed detailed analysis on 300 circuits to identify more specific scope and cost. Based on lessons learned from the 2020 projects, the cost to deploy automation had a wide range given the uncertainty in circuit reconductoring and substation upgrades needed to not overload and burn down circuits. With improved cost estimates for the 300 circuits the prioritization of projects in the Storm Resilience Model is improved. This increasing the overall benefit in decreasing major outage events for customers.
6. Lateral Undergrounding Branching' Approach – Based on a lessons learned evaluation, the project definition for lateral projects was adjusted to include a collection of electrically connected protection zones, or 'branches'. TEC's undergrounding design standard includes looping for added resilience. Based on the 2020 project execution it was identified that some of the projects included higher costs to achieve the full loop. By undergrounding all the electrically connected protection zones off a circuit feeder / mainline the higher costs will be mitigated since it can be designed to minimize the number of new underground miles.

1.3 Results & Conclusions

TEC and 1898 & Co. utilized a resilience-based planning approach to establish an overall budget level and identify and prioritize resilience investment in the T&D system. Figure 1-2 shows the results of the budget optimization analysis. Given the total level of potential investment, the budget optimization analysis was performed in $250 million increments up to $2.5 billion. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95. P50 to P65 levels represent a future world in which storm frequency and impact are close to average, P70 to P85 level represent a future world where storms are more frequent and intense, and P90 and P95 levels represent a future world where storm frequency and impacts are all high.

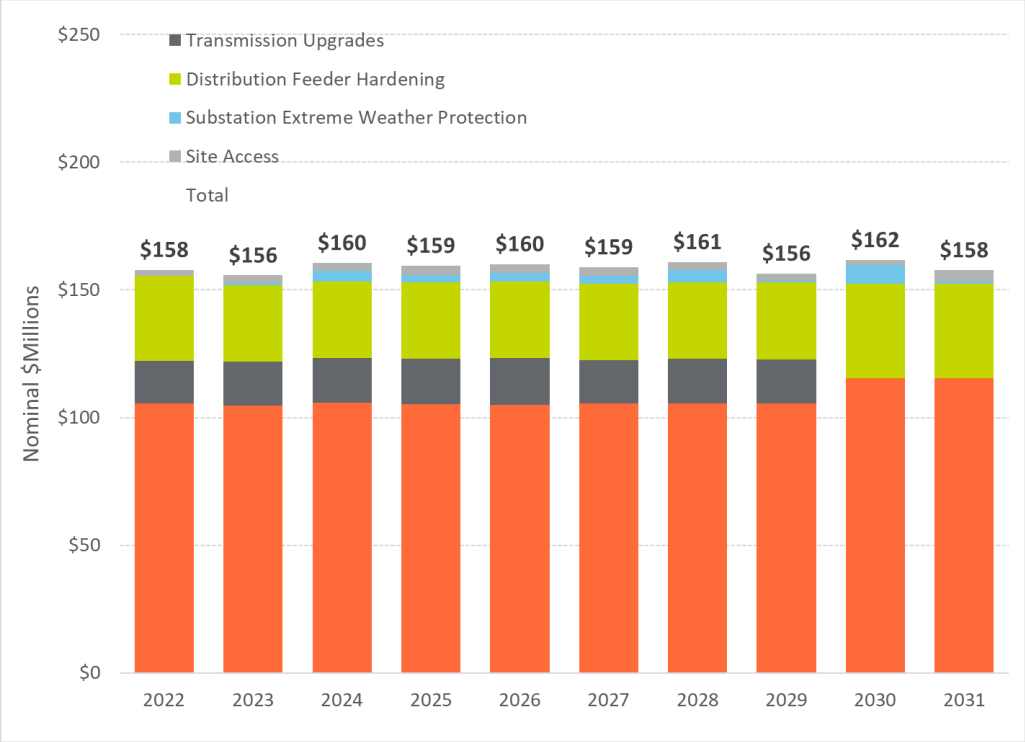
Figure 1-2: Budget Optimization Results



The figure shows significantly increasing levels of net benefit from the $250 million to $1.25 billion budget scenarios with the benefit level flattening from $1.25 billion to $1.75 billion and decreasing from $1.75 billion to $2.5 billion. The figure also shows the total investment level in 2021 dollars for the TEC Storm Protection Plan. The TEC overall investment level is right before the point of diminishing returns, which demonstrates that TEC's plan has an appropriate level of investment over the next 10 years capturing the hardening projects that provide the most value to customers.

Figure 1-3 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan investment level is approximately $1.59 billion. Lateral undergrounding makes up most of the total, accounting for 67.6 percent of the total investment. Feeder Hardening is second accounting for 20.0 percent. Transmission upgrades make up approximately 8.8 percent of the total with substations and transmission site access making up 1.7 percent and 2.0 percent, respectively.

Figure 1-3: Storm Protection Plan Investment Profile

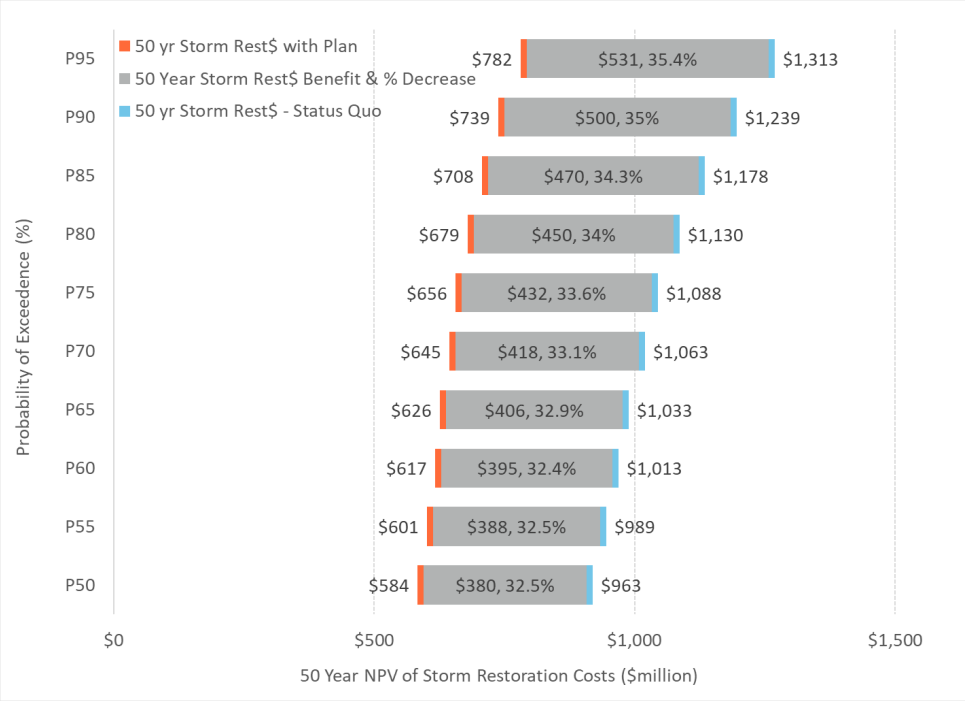


Customer benefits are calculated in terms of the:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

Figure 1-4 shows the range in restoration cost reduction at various probability of exceedance levels. To reiterate, the P50 to P65 level represents a future world in which storm frequency and impact are close to average, the P70 to P85 levels represent a future world where storms are more frequent and intense, and the P90 and P95 levels represent a future world where storm frequency and impacts are all high.

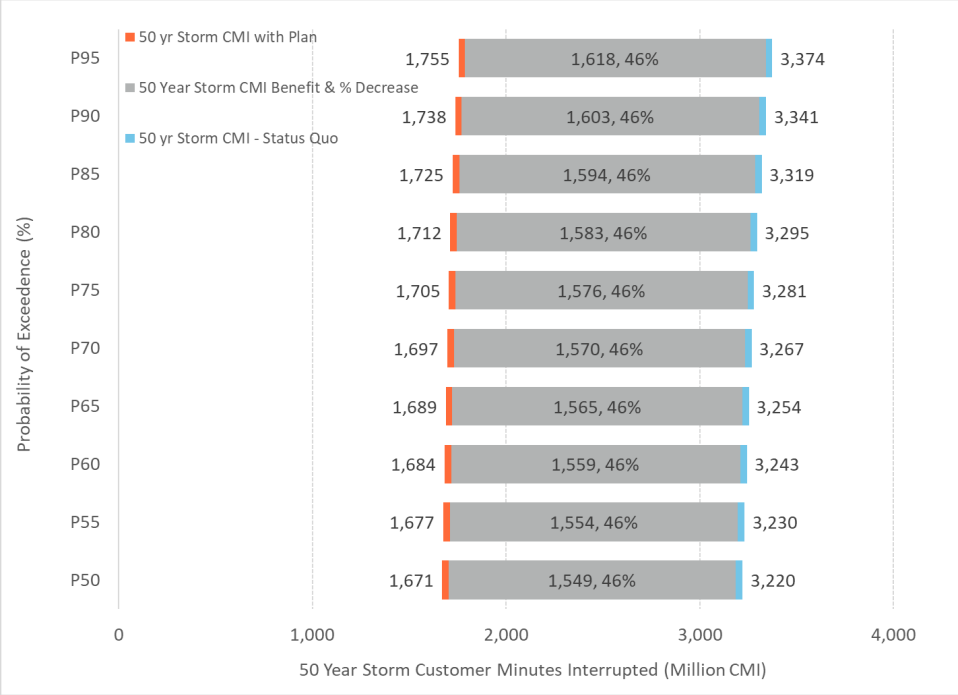
Figure 1-4: Storm Protection Plan Restoration Cost Benefit



The figure shows that the 50-year NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $960 million to $1,310 million. With the Storm Protection Plan, the restoration costs decrease by approximately 33 to 35 percent. The decrease in restoration costs is approximately $380 to $530 million. From an NPV perspective, the restoration cost benefit is approximately 24 to 33 percent of the Storm Protection Plan Investment Level. In other words, the reduction in restoration costs pay for 24 to 33 percent of the total invested capital costs.

Figure 1-5 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 46 percent decrease in the storm CMI over the next 50 years.

Figure 1-5: Storm Protection Plan Customer Benefit



The following include the conclusions of TEC's Storm Protection plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.59 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 1-2) shows the investment level is right before the point of diminishing returns.
- TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 33 to 35 percent. In relation to the plan's capital investment, the restoration costs savings range from 24 to 33 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 46 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.
- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.65 to $0.78 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.

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- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.
- The hardening investment will provide additional 'blue sky' benefits to customers not factored into this report.

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2.0 INTRODUCTION

Hurricanes have inflicted significant damage to Florida in recent years and parts of the state face years of recovery. One of the most important things Florida can do to prepare for the next major storm is to make the electric grid more resilient. When the grid can better withstand the impacts of storms, everyone benefits. Florida businesses and families save money because they can get back on their feet more quickly[1]. Florida Statute 366.96 allows for the comprehensive planning and front-end investment necessary to protect Florida's power supply. It also allows utilities to design integrated programs to address all phases of resilience which, in turn, will reduce storm-related restoration costs and outage times.

This document outlines the approach to

1. Calculate the benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level that maximizes customers' benefit while not exceeding TEC technical execution constraints

The resilience-based approach is an integrated data driven decision-making strategy comparing various storm hardening projects on a normalized and consistent basis. This approach takes an integrated asset management perspective, a bottom-up approach starting at the asset level. Each asset is evaluated for its likelihood of failure in a storm event. Additionally, the consequence of failure is also evaluated at the asset level in terms of the restoration costs and CMI. Assets are rolled up to hardening projects and hardening projects are then rolled up to programs. Each project only hardens the assets that provide the most benefit to customers and that align with TEC's design standards.

This report outlines project prioritization and benefits calculations for the following TEC storm hardening programs:

- Distribution Lateral Undergrounding
- Transmission Asset Upgrades

[1] State Rep. Randy Fine and State Sen. Joe Gruters, Sun Sentinel, May 2019

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- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

The other programs within TEC's Storm Protection Plan, Vegetation Management, Infrastructure Inspections, and Distribution Pole Upgrades, are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's Storm Protection Plan. Similarly, their benefits are described in other portions of TEC's Storm Protection Plan.

The following sections outline the foundation and background necessary to understand the rest of this report. These sections include a review of:

- Topic of resilience
- Resilience as the project assessment approach
- TEC asset base evaluated for resilience measures
- Resilience-based planning approach
- Resilience Investment Business Case Results

2.1 Resilience as the Benefits Assessment

Resilience has many faces. It looks different to different people and organizations depending on their challenges and focus. Is it more important to avoid an event from disrupting your business or is it more important to recover quickly? Both are important and TEC's approach considers both of these questions and more.

Resilience has been defined differently by many organizations. In a 2013 paper, the National Association of Regulatory Utility Commissioners (NARUC) paraphrased its own definition of resilience in a manner that is simple and easy to understand.

> *"it's the gear, the people and the way the people operate the gear immediately before, during and after a bad day that keeps everything going and minimizes the scale and duration of any interruptions."*

Before that, the National Infrastructure Advisory Council (NIAC) provided a definition that is often quoted, and which includes elements used in many other definitions. It states that resilience is

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> *"The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."*

The NIAC definition includes a system's ability to absorb and adapt. These important characteristics were also used by Argonne National Laboratory (ANL) in its work on state and social resilience and were incorporated into Pacific Northwest National Laboratory's (PNNL) work on the resilience impacts of transactive energy systems. The ANL approach can be used to break resilience into four phases that also align with NARUC's elegantly simple description. The difference is that ANL explicitly includes the ability of the system to recognize and mitigate potential failures before they happen. These four phases are described below.

- Prepare (Before)
  The grid is running normally but the system is preparing for potential disruptions.
- Mitigate (Before)
  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption. During this time the precursors are normally detectable.
- Respond (During)
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).
- Recover (After)
  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.

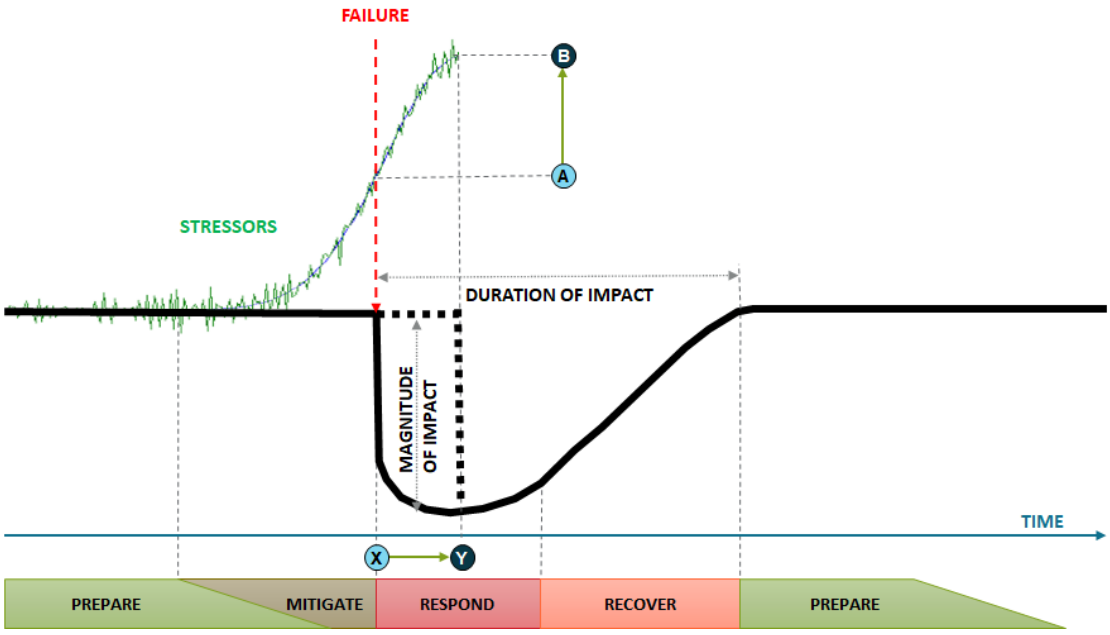
This is depicted graphically in Figure 2-1. The green line represents an underlying issue that is stressing the grid, and which increases in magnitude until it reaches a point where it impacts the operation of the grid and causes an outage. The origin of the stress may be electrical due to a failing component, or external due to storms or other events. The black line shows the status of the entire system or parts of the system (e.g. transmission circuits). The "pit" depicted after the event occurs represents the impact on a system in terms of the magnitude of impact (vertical) and the duration (horizontal). For utilities this can be measured after the event and is used by the Institute of Electrical and Electronics Engineers

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(IEEE) 1366 to calculate reliability metrics. If TEC is able to detect the strain on the grid caused by these stresses then it increases the opportunity to act before a failure occurs, thus reducing or avoiding the impact of the subsequent event.

Figure 2-1 represents a conceptual view of resilience. It can be used to depict a specific transmission line or the whole transmission system. If the figure is used to represent a specific line, it represents the impact of the event on that line. If the figure is used to represent the impact on the whole TEC system, it represents the aggregated impacts of the event (storm) and the multiple outages that may result from it. Note that whether this is a specific or overall depiction of resilience there is no quantification of time. Time increases from left to right but due to the nature of events that may occur there are no timescales used.

Figure 2-1: Phases of Resilience



For example, hardening of the overhead transmission system is targeted at the “prepare” phase. Mitigation depends on the ability to detect developing issues and includes the capability to detect stresses on the grid by monitoring it. Responding to an event as it is impacting the grid depends on the ability to make informed decisions, to deploy crews rapidly to the right place at the right time, and for the grid to adapt to the stresses through reconfiguration. Recovery depends on coordinated activity and good planning.

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In Figure 2-1, the level of strain on the grid caused by the early effects of an event that could cause asset failure is represented by 'A'. As an example, this might be a wooden transmission pole, with failure occurring at time 'X'. In this example suppose a steel monopole was used to replace the wood pole transmission structure. The monopole might succumb to failure at higher strain levels depicted by 'B' and would result in later failure at time 'Y'.

For the line where this occurred, this illustrates how hardening did not prevent failure but delayed it and shortened the outage duration. If it takes more work to erect a new monopole it might increase recovery time for a specific line, yet if less steel monopoles failed relative to the number of wood poles that would have failed, there would be less to replace and the overall system outage time and recovery time would be reduced. Fewer asset failures means that more crews will be able to work on the assets that do fail, which can have a multiplying effect on outage reduction time.

The Storm Resilience Model evaluates the phases of resilience for storms on both the entire system and at the sub-system level (substations, transmission circuit, site access, feeder, and lateral). Section 2.3 provides additional detail on this evaluation approach.

2.2 Evaluated System for Resilience Investment

The Storm Resilience Model (described in more detail in Section 2.3) is comprehensive in that it evaluates nearly all of TEC's T&D system. Table 2-1 shows the asset types and counts included in the Storm Resilience Model.

Table 2-1: TEC Asset Base Modeled

Asset Type	Units	Value
Distribution Circuits	**[count]**	**710**
Feeder Poles	[count]	58,700
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,300
Lateral OH Primary	[miles]	3,900
Transmission Circuits	**[count]**	**215**
Wood Poles	[count]	5,000
Steel / Concrete / Lattice Structures	[count]	20,400
Conductor	[miles]	1,300
Substations	**[count]**	**9**
Site Access	**[count]**	**44**
Roads	[count]	25
Bridges	[count]	19

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1. All of the assets are strategically grouped into potential hardening projects, and only the assets that require hardening are included in the projects. For distribution projects, assets were grouped by their most upstream protection device, which was either a breaker, a recloser, trip savers, or a fuse. For lateral projects, where applicable, several protection zones were combined that were electrically connected right off the circuit feeder. This approach focuses on reducing customer outages. The objective is to harden each asset that could fail and result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves weak links that could potentially fail in a storm. Rolling assets into projects at the protection device level allows for hardening of all weak links in the circuit and for capturing the full benefit for customers.

For lateral projects, those with a fuse or trip saver protection device, the preferred hardening approach is to underground the overhead circuits. Since the main cause of storm related outages, especially for weakened structures, is the wind blowing vegetation into conductor, causing structure failures, undergrounding lateral lines provides full storm hardening benefits. While rebuilding overhead laterals to a stronger design standard (i.e. bigger and stronger poles and wires) would provide some resilience benefit, it would not solve the vegetation issues, since the high wind speeds can blow tree limbs from outside the trim zone into the conductor.

For distribution feeder projects, those with a recloser or breaker protection device, the preferred hardening approach is to rebuild to a storm resilient overhead design standard and add automation hardening. Assets in these projects include older wood poles and those with a ‘poor’ condition rating. Additionally, poles with a class that is not better than ‘1’ were also included in these projects. The combination of the physical hardening and automation hardening provides significant resilience benefit for feeders. The physical hardening addresses the weakened infrastructure storm failure component. While the vegetation outside the trim zone as still a concern, most distribution feeders are built along main streets where vegetation densities outside the trim zone are typically less than compared to laterals. Further, the feeder automation hardening allows for automated switching to perform ‘self-healing’ functions to mitigate vegetation outside trim zone and other types of outages. The combination of the physical and automation hardening provide a balanced resilience strategy for feeders. It should be noted that this balanced strategy with automation hardening is not available for laterals. As such, undergrounding is preferred approach for lateral hardening and overhead physical hardening combined with automation hardening is the preferred approach for feeders.

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At the transmission circuit level, wood poles were identified for hardening by replacing with non-wood materials like steel, spun concrete, and composites. These materials have consistent external shell strength while wood poles can vary widely and are more likely to fail. Transmission wood poles were grouped at the circuit level into projects.

TEC identified 44 separate transmission access, road, and bridge projects based on field inspection of the system.

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH model identified 59 substations with a flood risk, depending on the hurricane category. Based on TEC's more detailed assessment, 9 substations were identified that included flooding risk to the level that could justify investment.

Table 2-2 contains a list of potential hardening projects based on the methodology outlined above. As seen below, there are a significant number of potential hardening projects, over 13,800. The following sections outline the approach to selecting the hardening projects that provide the most value to customers from a restoration cost and CMI decrease perspective.

Table 2-2: Potential Hardening Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	12,310
Transmission Asset Upgrades	107
Substation Extreme Weather Hardening	9
Distribution Overhead Feeder Hardening	1,385
Transmission Access Enhancements	44
Total	13,855

2.3 Resilience Planning Approach Overview

The resilience-based planning approach calculates the benefit of storm hardening projects from a customer perspective. This approach calculates the resilience benefit at the asset, project, and program level within the Storm Resilience Model. The results of the Storm Resilience Model are a:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

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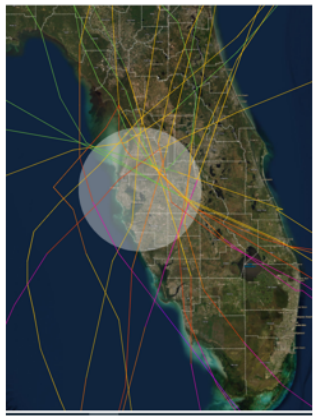
Figure 2-2 provides an overview of the resilience planning approach to calculate the customer benefit, restoration cost reduction and CMI reduction of hardening projects and prioritization of the projects.

2.3.1 Major Storms Event Database

Since the magnitude of the restoration cost decrease and CMI decrease is dependent on the frequency and magnitude of future major storm events, the Storm Resilience Model starts with the 'universe' of major storm events that could impact TEC's service territory, the Major Events Storms Database.

Figure 2-2: Resilience Planning Approach Overview

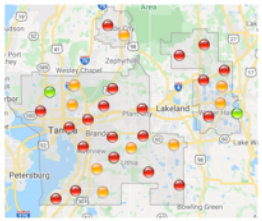
Major Storm Event Database



- Storm Types & Scenarios.
- 13 Unique Storm Types
- 99 Storm Scenarios
- NOAA Historical Analysis
- Failure Mode Basis
  - "Direct Hits"
  - "Partial Hits"
  - "Peripheral Hits"
  - Land or Sea
- Data Capture
  - Probability
  - System Impacted
  - Duration
  - Cost to Restore

Storm Impact Model (SIM)

Status Quo



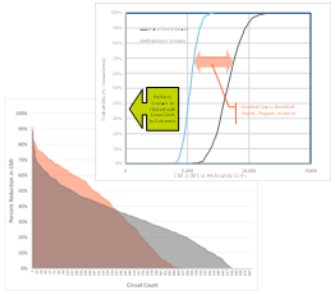
- SIM models impact of storm against TEC system
  - Allocates system failures based on LOF scores for each project. Vegetation, Age & Condition, Wind, and Flood Modeling
  - Storm Restoration Cost Multipliers
- Calculates Hardened benefits for all "projects' for each storm event
- Benefits = Status Quo – Hardened System

Hardened System

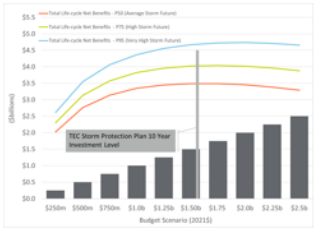


Resilience Benefit Module

- Monte Carlo Simulation to establish 'worlds' of future major events over 50 years.
- Calculation of storm customer outage duration and monetization of CMI
- Automation Hardening – Historical OMS
- Distribution of results by Project for Status Quo and Hardened Scenarios
  - Cost of Project
  - Restoration Costs
  - CMI and Monetized CMI
- Resilience Benefit Calculation (Prioritization Metric)



Budget Optimization & Project Prioritization



- Resilience Benefit Cost Ratio: P50, P75, and P95
- Budget Scenarios
- Point of Diminishing Returns
- Plan Development and Constraints
- Project Bundling



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The Major Storms Event Database describes the stressor that causes system failure. The database also provides the high-level impact to the system of the storm stressor. The major events database includes the following:

- Storm Type
- Probability of a storm occurring
- Restoration Costs
- Percentage of the system impacted
- Duration of the storm

The major storm events database includes 13 unique storm types. The storm types include the various hurricane categories and direction they come from (hurricane impacts from the Gulf side are much different than from the Florida side). Each storm type has a range of probabilities and impacts. With the various combinations (high probability with lower consequence and low probability with high consequence, etc.) the Major Storms Event Database includes 99 different storm scenarios. Section 3.0 provides additional detail on the Major Storms Event Database.

2.3.2 Storm Impact Model

Each storm scenario is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Storm Impact Model calculates the restoration costs and customers impacted by system failures for both the Status Quo and Hardened Scenarios. The Storm Impact Model identifies the damaged portions of the system by modeling the elements that cause failures in the TEC asset base.

For circuits, the main cause of failure is wind blowing vegetation onto conductor causing conductor or structures to fail. If structures (i.e. wood poles) have any deterioration, for example rot, they are more susceptible to failure. The Storm Impact Model calculates a storm LOF score for each asset based on a combination of the vegetation rating, age and condition rating, and wind zone rating. The vegetation rating factor is based on the vegetation density around the conductor. The age and condition rating utilize expected remaining life curves with the asset's 'effective' age, determined using condition data. The wind zone rating is based on the wind zone that the asset is located within. The Storm Impact Model includes a framework that normalizes the three ratings with each other to develop one overall storm LOF score for all circuit assets. The project level scores are equal to the sum of the asset scores normalized for length. The project level scores are then used to rank each project against each other to

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identify the likely lateral, backbone, or transmission circuit to fail for each storm type. The model estimates the weighted storm LOF based on the asset level scoring.

The model determines which substations are likely to flood during various storm types based on the flood modeling analysis. That analysis provides the flood level, meaning feet of water above the site elevation, for various storm types.

Each transmission site access project provides access to one or more transmission circuits. If a major storm event causes a transmission outage and the access location is also impacted, it can take longer to restore the system. The Storm Impact Model uses each transmission circuit's storm LOF to estimate the LOF of each site access during a storm. For instance, if site access 'A' is needed to gain access to Circuit '1' and '4', the storm likelihood for site access 'A' equals the storm likelihood of failure for Circuit '1' and '4' combined.

Once the Storm Impact model identifies the portions of the system that are damaged and caused an outage for a specific storm, it then calculates the restoration costs to rebuild the system to provide service. The restoration costs are based on the multipliers for storm replacement over the planned replacement costs using TEC labor and procured materials only. The restoration cost multipliers are based on historical storm events and the expected outside labor and expedited material cost needed to restore the system.

Similarly, the Storm Impact Model calculates the CMI for each project. Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset in the Storm Impact Model. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known customer count to calculate the CMI. The CMI benefit is monetized using DOE's ICE Calculator for project prioritization purposes.

Finally, the Storm Impact Model then calculates the reductions in project storm LOF, restoration costs, and CMI for each hardening project. The output of the Storm Impact Model is the project LOF, CMI, monetized CMI, and restoration costs for each of the 99 storms for both the Status Quo and Hardened scenarios.

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2.3.3 Resilience Benefit Calculation

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future "storm worlds" and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

2.3.4 Project Scheduling and Budget Optimization

The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest ratio of resilience benefit to cost. It also performs a budget optimization simulation to identify the point of diminishing returns for hardening investments for the 10-year period and portions of the system evaluated.

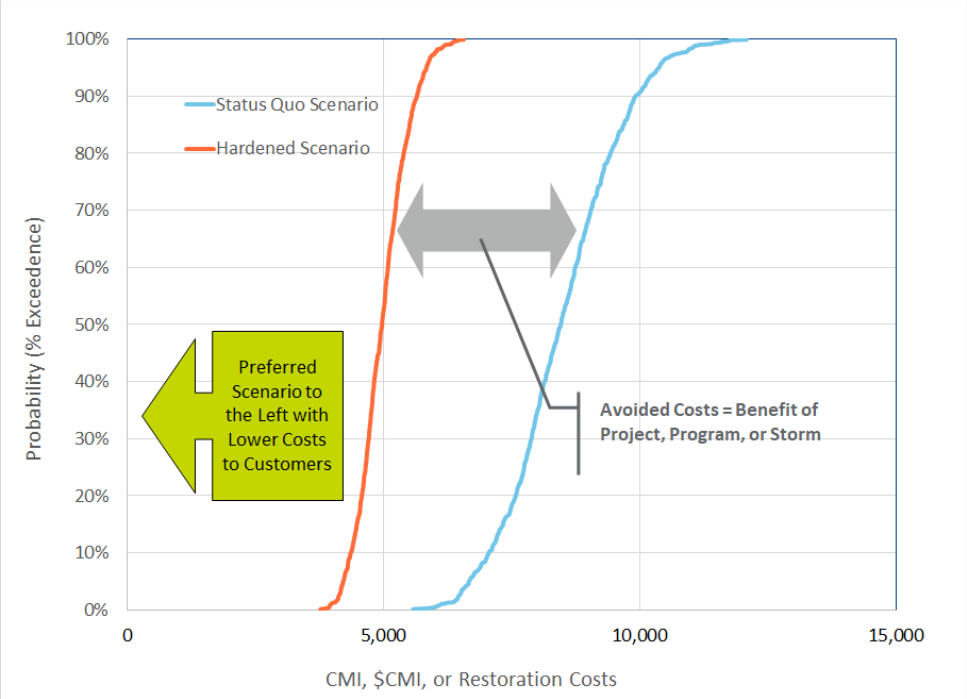
The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This calculation is performed for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates TEC's technical and operational constraints in scheduling the projects such as contractor capacity and scheduling transmission planned outages. Using the Resilience Benefit Calculation and project scheduling model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

Budget optimization is performed by running the model over a wide range of budget scenarios. Each budget scenario calculates the range in reduction of restoration costs and CMI. The budget optimization calculates the point where incremental hardening investments result in diminishing returns in customer benefit.

2.4 S-Curves and Resilience Benefit

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. In layman's terms, the thousand results are sorted from lowest to highest (cumulative ascending) and then charted. Figure 2-3 shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios.

Figure 2-3: Status Quo and Hardened Results Distribution Example

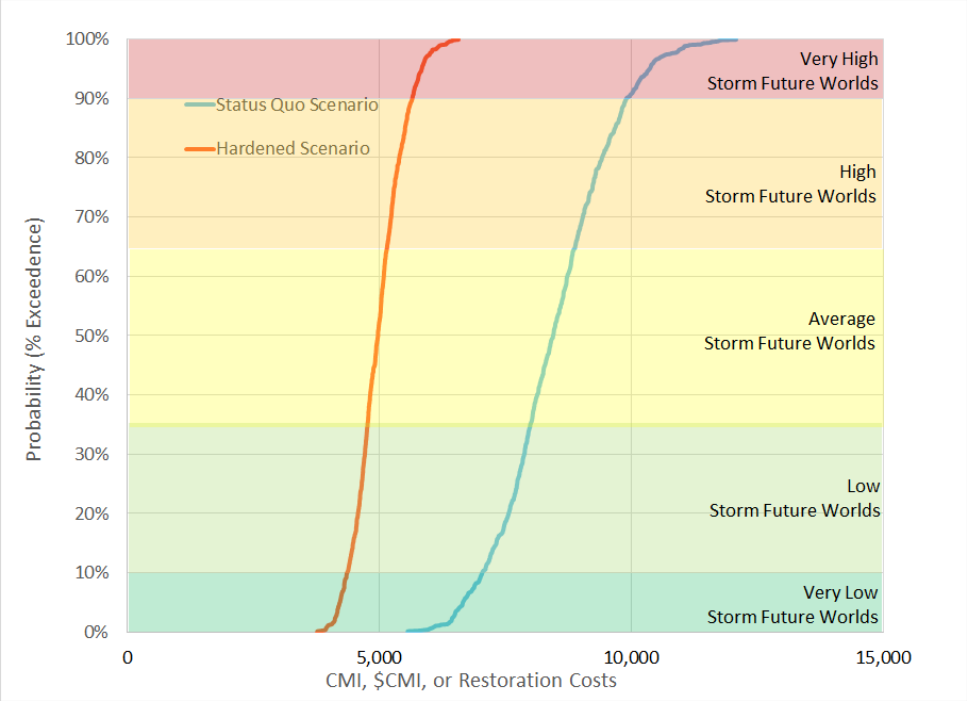


The horizontal axis shows the storm cost in terms of CMI, monetized CMI, or restoration costs. The values in the figure are illustrative. The vertical axis shows the percent exceedance values. For the Hardened Scenario, the chart shows a value of 5,000 at the 40-percentile level. This means there is a 40 percent confidence that the Hardened Scenario will have a value of 5,000 or less. Each of the probability levels is often referred to as the P-value. In this case the P40 (40 percentile) has a value of 5,000 for the Hardened Scenario.

Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

The S-Curves typically have a linear slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e. vertical) the less range in the result. The more horizontal the slope the wider the range and variability in the results. Figure 2-4 provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

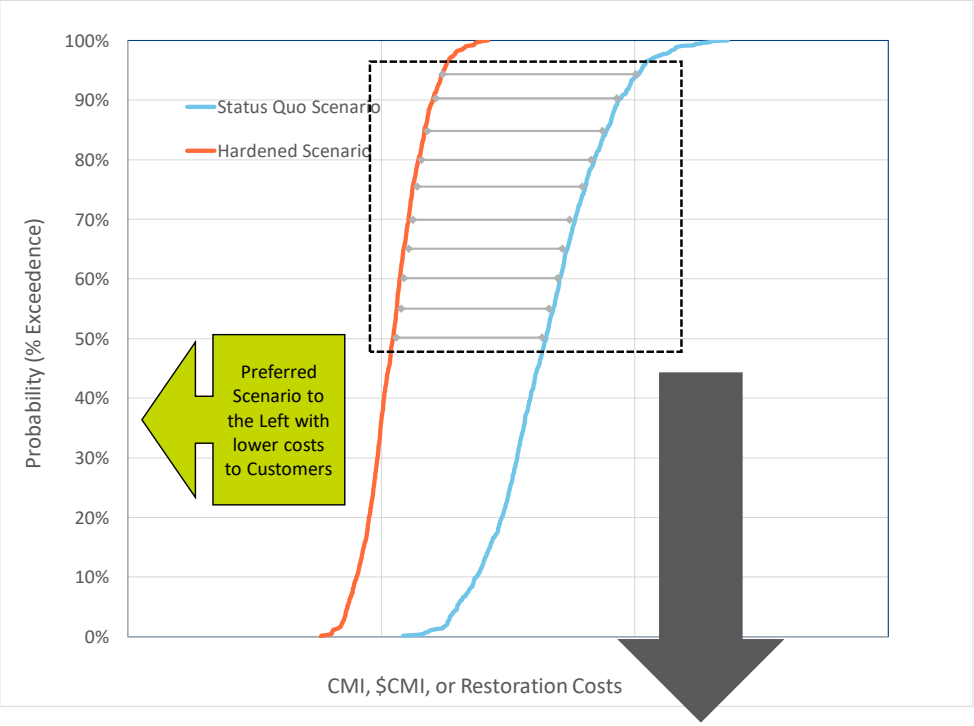
Figure 2-4: S-Curves and Future Storms



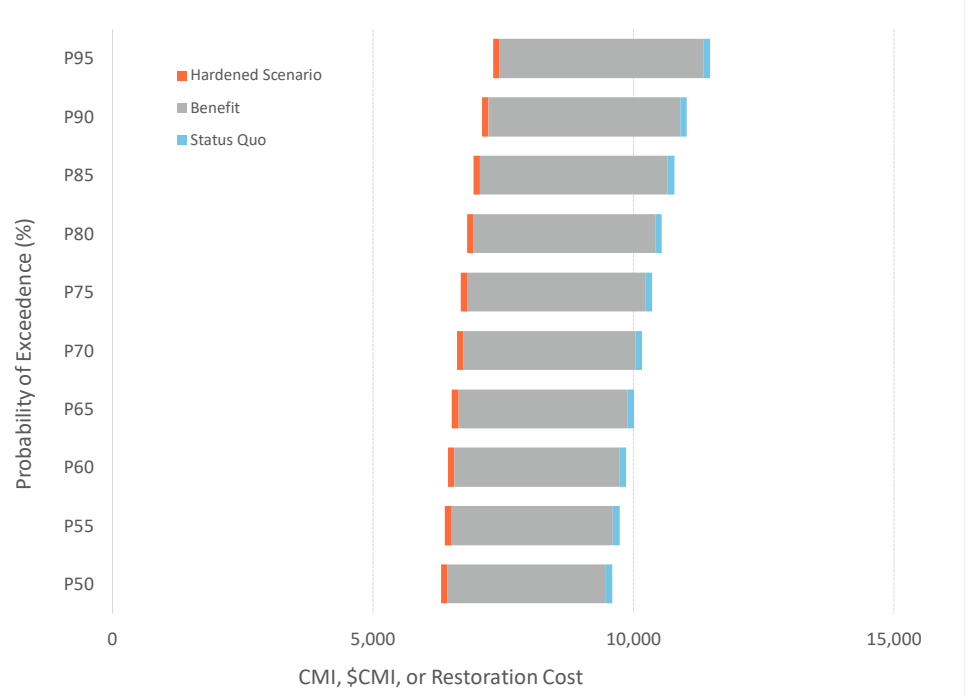
For the storm resilience evaluation, the top portion of the S-curves is the focus as it includes the average to very high storm futures, this is referred to as the resilience portion of the curve. Rather than show the entire S-curve, the results in the report will show specific P-values to highlight the gap between the 'Status Quo' and Hardened Scenarios. Additionally, highlighting the specific P-values can be more intuitive. Figure 2-5 illustrates this concept of looking at the top part of the S-curves and showing the P-values. Section 7.0 includes results figures similar to the second figure in Figure 2-5 below.

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Figure 2-5: S-Curves and Resilience Focus



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3.0 MAJOR STORMS EVENT DATABASE

The first main component of the Storm Resilience Model is the Major Storms Event Database. The database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for a range of storm stressors. This section describes the data sources and approach used to develop the database. Since the benefits of hardening projects are directly related to the frequency and impact of major storm events, the resilience-based planning approach starts with developing the range of storm types that could impact TEC's service territory. The impact of major storm events to the TEC system is dependent on following:

- Wind speeds of the storm (i.e. category of storm). Higher wind speeds means more trees and tree limbs from inside and outside of the tree trim zone on the conductor. The additional weight and forces on the conductor cause pole or tower failures. At high enough wind speeds, the wind speed alone can cause a structure failure.
- Direction that it comes from (Gulf or Florida). Storms from the Gulf could bring storm surge and associated flooding. Additionally, the counter-clockwise storm band rotation include different level of energy (i.e. wind speed) if they have been over land for a period of time.
- Eye Distance from TEC's territory. Storms that directly hit Tampa are impactful since the entire service territory effectively gets hit twice by the storm bands. Additionally, the total duration of the event is longer. For more distant storms, only a few storm bands may hit the TEC service territory.

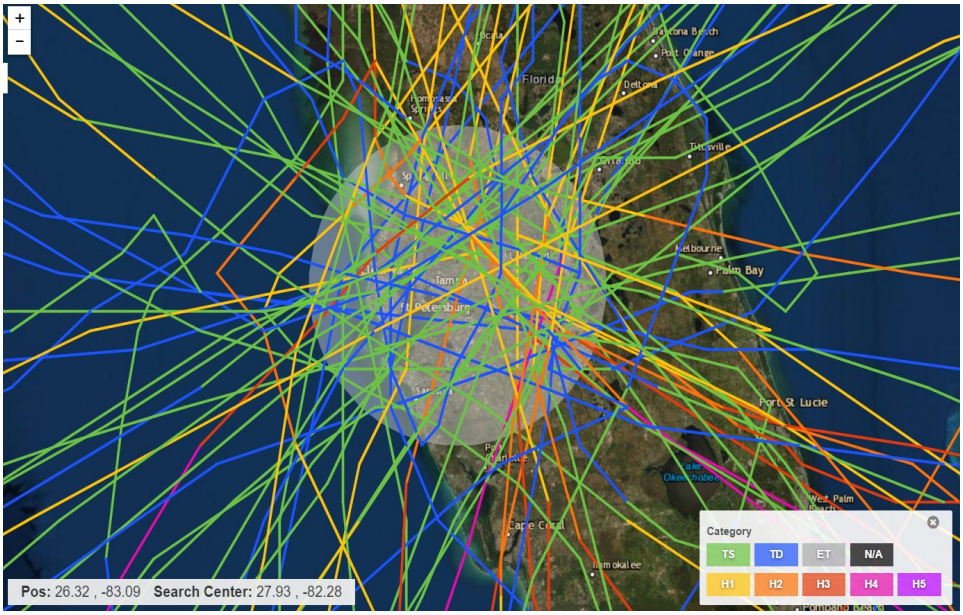
The major storms event database includes the range of storm stressors that would cause an outage(s) to the TEC system based on the three main contributing factors above. The database includes both the probability of the storm stressor, impact in terms of restoration costs and duration, and impact with respect to which parts of the TEC system fail. The following sections provide additional analysis and commentary on how these assumptions were developed for the storms event database.

3.1 Analysis of NOAA Major Storm Events

The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 169years, beginning in 1852. This database was mined to evaluate the different types and frequency of major storms to impact the TEC service territory. Figure 3-1 provides an example screen

shot from NOAA's storms database. It shows all the events, including path and category, to come within 50 miles of TEC's service territory center.

Figure 3-1: NOAA Example Output – 50 Mile Radius



Source: https://coast.noaa.gov/hurricanes/

This database was mined for all major event types up to 150 miles from TEC service territory center. The 150-mile radius was selected since many hurricanes can have diameters of 300 miles where some of the hurricane storm bands impact a significant portion of the TEC service territory. Additionally, the database was mined for the category of the storm as it hit the TEC service territory. The analysis of NOAA's database was done for the following types of storm categories:

- 'Direct Hits' – 50 Mile Radius from the Gulf and Florida directions. The max wind speeds hit all or significant portions of TEC service territory twice, once from the front end and again on the back end of the storm. Additionally, the wind speeds cause all the assets and vegetation to move in one direction as the storm comes in and in the opposite direction as it moves out. This double exposure to the system causes significant system failures.
- 'Partial Hits' – 51 to 100 Mile Radius. At this radius, the storm bands hit a significant portion of the TEC service territory. Wind speeds are typically at their highest at the outer edge of the storm bands. The storm passes through the territory once, so to speak, minimizing damage

relative to a 'direct hit'. For large category storms, the 'Partial Hit' could still cause more damage than a 'Direct Hit' small storm.

- 'Peripheral Hits' – 101 to 150 Mile Radius. Since hurricanes can be 300 miles wide in diameter, some of the storm bands can hit a fairly large portion of the system even if the main body of the storm misses the service area.

Table 3-1 includes the summary results from the NOAA database of storms to hit or nearly hit the TEC service territory since 1852.

Table 3-1: Historical Storm Summary

Event Type	Direct Hits Gulf	Direct Hits Florida	Direct Hits Total	Partial Hits	Peripheral Hits	Total
Cat 5	0	0	0	0	0	0
Cat 4	0	1	1	0	1	2
Cat 3	0	1	1	5	4	10
Cat 2	4	1	5	2	8	15
Cat 1	6	6	12	14	8	34
Tropical Storm	12	20	32	30	29	91
Tropical Depression	10	8	18	17	NA	35
Total	32	37	69	68	50	187

Table 3-1 shows a total of 187 storms to hit the Tampa area since 1852. A total of 69 were direct hits within 50 miles, 68 were partial hits in the 51 to 100-mile radius, and 50 were peripheral hits in the 101 to 150 mile radius. The table also shows very few category 4 and above events, 2 out of 187, with one 'Direct Hit'. While there are 10 Category 3 types storms, only 1 is a 'Direct Hit'. Nearly 20 percent of the events are Category 1 Hurricanes. Almost two thirds of the events are Tropical Storms or Tropical Depressions. For direct hits, the results show approximately 46 percent of the events come from the Gulf of Mexico while the other 54 percent come over Florida. The direction the storm comes from has significant impact on the overall damage to TEC's system. Based on these results and the various

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quantities by event type, the following 13 unique storm types serves as the foundation for the Major Storms Event Database:

1. Category 3 and Above 'Direct Hit' from the Gulf
2. Category 1 & 2 'Direct Hit' over Florida
3. Category 1 & 2 'Direct Hit' from the Gulf
4. Tropical Storm 'Direct Hit'
5. Tropical Depression 'Direct Hit'
6. Localized Event 'Direct Hit'
7. Category 3 and Above 'Partial Hit'
8. Category 1 & 2 'Partial Hit'
9. Tropical Storm 'Partial Hit'
10. Tropical Depression 'Partial Hit'
11. Category 3 and Above 'Peripheral Hit'
12. Category 1 & 2 'Peripheral Hit'
13. Tropical Storm 'Peripheral Hit'

Each of these storm types serve as a stressor on the system that causes an outage and damage. The next three subsections provide a historical analysis of storm events that impacted TEC's Service Territory to provide information on the probability of each of the 13 storm types.

3.1.2 Direct Hits (50 Miles)

Figure 3-2 provides a historical view of the number of major storm events to hit the TEC service territory over the last 169 years. The figure shows 6 different storm types. Figure 3-3 converts the storm data in Figure 3-2 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951. Review of the two figures shows there have been no Category 3 or above hurricanes to hit the TEC service territory from the Florida side.

Figure 3-2: "Direct Hits" (50 Miles) Over Time[2]

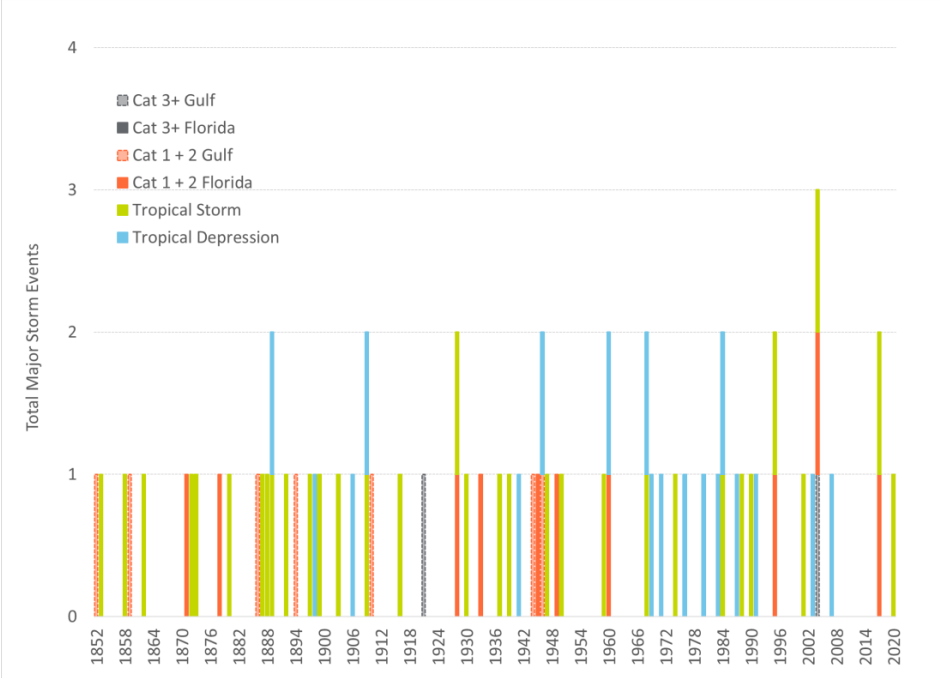


Figure 3-3 shows an average of approximately 40 storms for each rolling 100-year period from 1951 to 2020. The rolling 100-year average results show a stability to the number of 'Direct Hits' over the time horizon. The figure shows a relative stability in the number of Category 1 and above storms over the period. Even though there is relative stability in the 40-storm average for the 100-year rolling average time horizon, the figure shows a decrease in the number of tropical storms with a corresponding increase in the number of tropical depressions. Figure 3-4 converts the totals for each 100-year period in Figure 3-3 to probabilities by dividing by 100.

[2] Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Figure 3-3: "Direct Hits" (50 Miles) 100 Year Rolling Average[3]

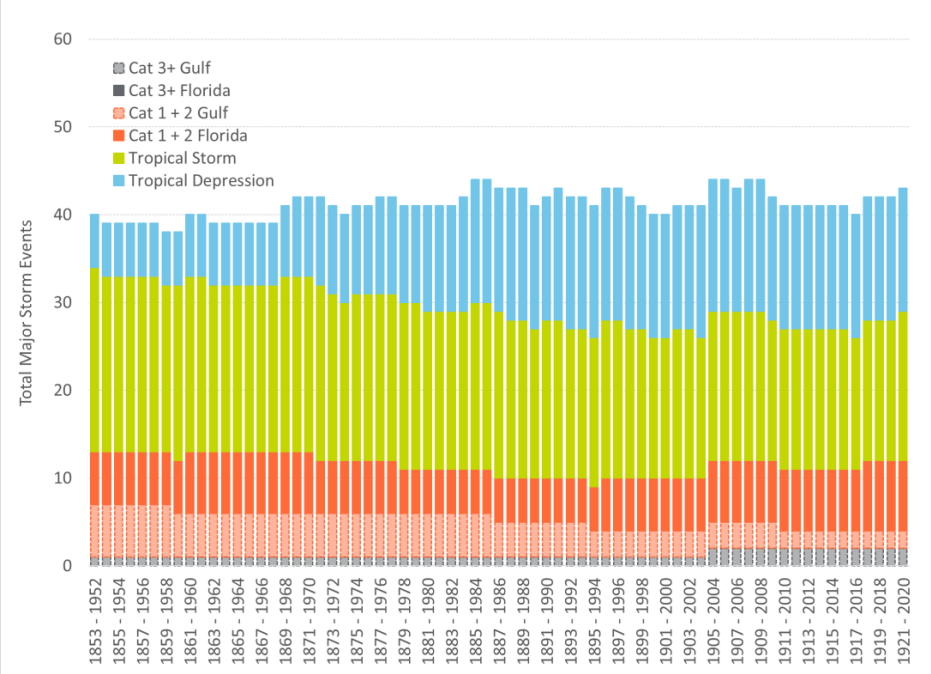
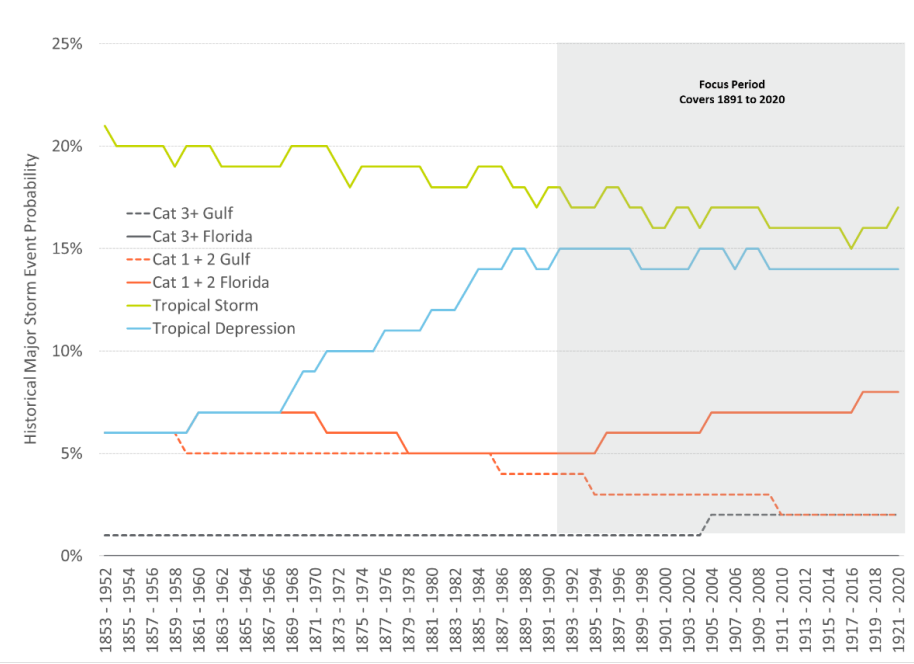


Figure 3-4: "Direct Hits" (50 Miles) 100 Year Rolling Probability[3]



[3] See Footnote 2

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The figure shows a low historical probability for Category 3 and above events from the Gulf of 1 to 2 percent. Additionally, there has been a decrease in the probability of Category 1 and 2 storms from the Gulf with a corresponding increase in the number coming from the Florida side. The story is similar for Tropical Storms and Tropical Depressions. The number of Tropical Storms shows a steady relative decline with a significant increase in probability of Tropical Depression until 1990 and stabilizes thereafter. As the figure shows, the probabilities of failure show a relative stability for the 100-year rolling average probabilities from 1990 to 2020, which encompasses thirty 100-year periods. Given the recent stability over this period these probability ranges were utilized in the Major Storms Event Database.

3.1.3 Partial Hits (51 to 100 Miles)

Figure 3-5 provides a historical view of the number of major storm events that have partially hit the TEC service territory over the last 169 years. A storm is classified as a partial hit if the eye passes between 51 and 100 miles from TEC's service territory. The figure shows 4 different storm types. Figure 3-6 converts the storm data in Figure 3-5 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951. The 100-year rolling average of storm events for partial hits follows a similar profile to that of direct hits, but it does show that Category 3 storms have hit TEC's service territory within a 51 to 100-mile radius throughout the rolling average windows in the analysis. This illustrates that there is a real possibility that TEC's service territory will be impacted by a Category 3 or higher hurricane each year.

Figure 3-5: "Partial Hits" (51 to 100 Miles)[4]

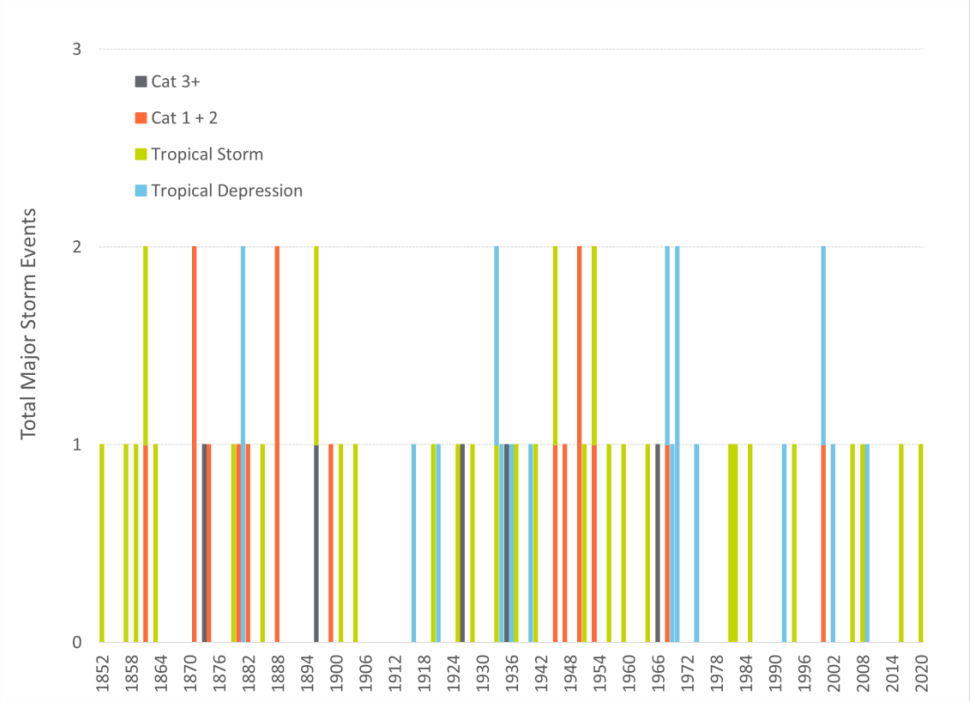


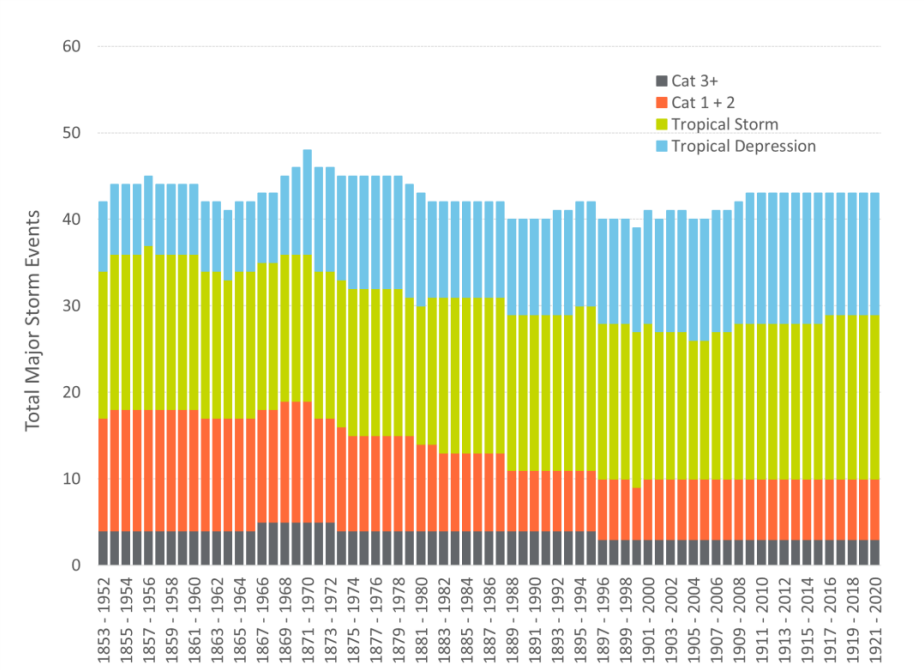
Figure 3-5 shows an average storm count of approximately 42 for each rolling 100-year period from 1951 to 2020. The rolling 100-year average results show a stability to the number of 'Partial Hits' over the time horizon. The figure shows a slight decline in the number of Category 1 and 2 storms over the period. As the overall storm count has remained stable, the slight decline in Category 1 and 2 storms was inversely mirrored by an increase in tropical depression counts.

Figure 3-7 converts the totals for each 100-year period in Figure 3-6 to probabilities by dividing by 100. This figure further illustrates the change in storm type distributions as Category 1 and 2 storms gave way to tropical depressions. The reason for the shift is unknown, but it is possible that this change is due to increases in data accuracy or recording procedures over time.

[4] See Footnote 2

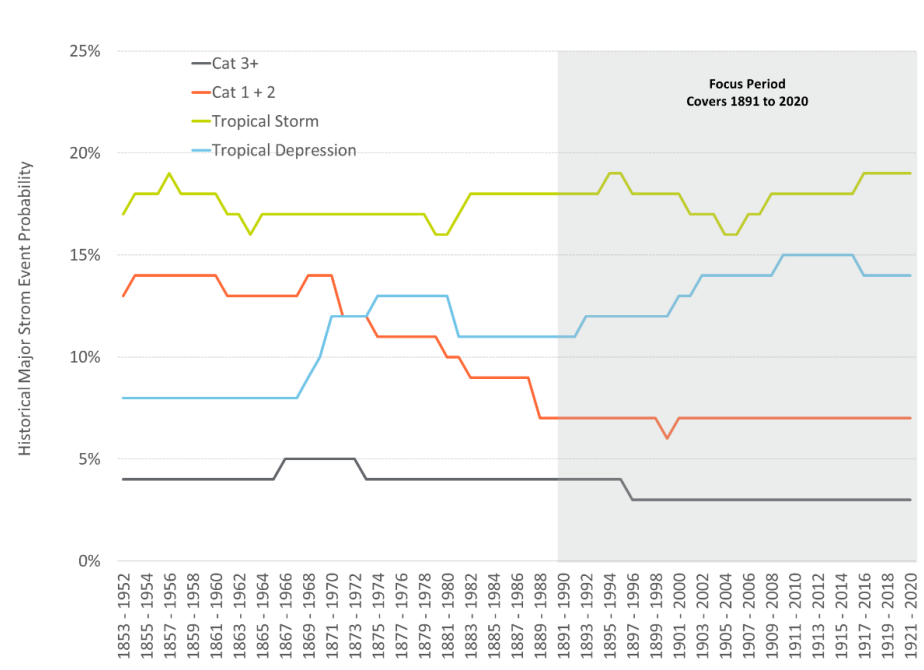
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Figure 3-6: "Partial Hits" (51 to 100 Miles) 100 Year Rolling Average[5]



[5] See Footnote 2

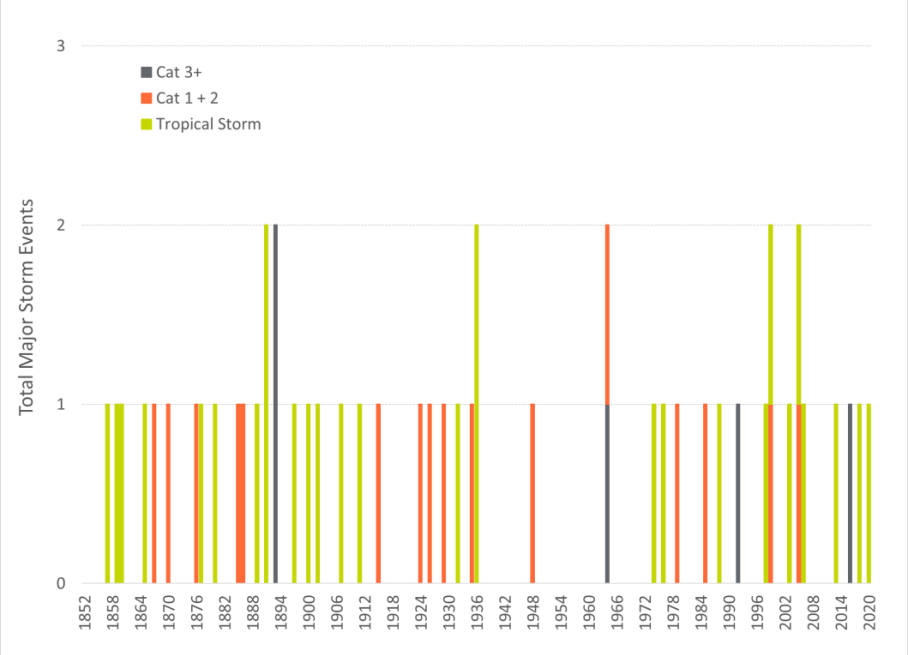
Figure 3-7: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[5]



3.1.4 Peripheral Hits (101 to 150 Miles)

Figure 3-8 provides a historical view of the number of major storm events that have hit TEC's service territory in the periphery over the last 169 years. A storm is classified as a partial hit if the eye passes between 101 and 150 miles from TEC's service territory. Since tropical depressions within this range may not be large enough to impact TEC's service territory, the figure only includes Tropical Storms, Category 1 and 2 storms, and Category 3 and higher storms. Figure 3-9 converts the storm data in Figure 3-8 to show the total storm count for a 100-year rolling average starting with the period 1853 to 1952.

Figure 3-8: "Peripheral Hits" (101 to 150 Miles)[6]



The 100-year rolling average of storm events for peripheral hits shows a slight decline from 30 to 25 storms, mostly driven by a decline in Tropical Storms.

Figure 3-10 converts the totals for each 100-year period in Figure 3-9 by dividing by 100. This figure further illustrates the decline in probability of Tropical Storms over the analysis period.

[6] See Footnote 2

Figure 3-9: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Avg.[7]

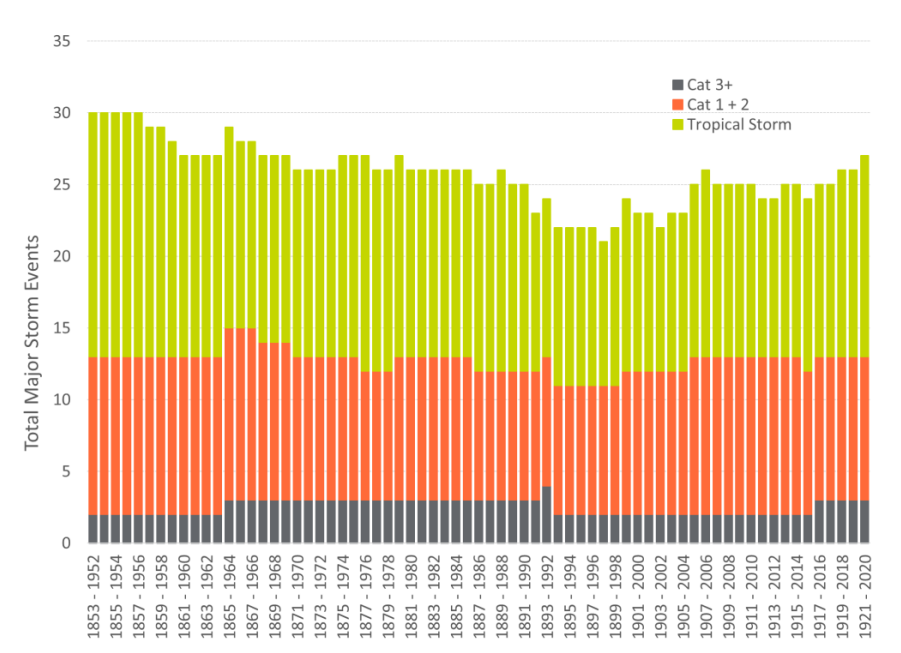


Figure 3-10: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[7]



[7] See Footnote 2

3.2 Major Storms in the Future

Section 3.1 reviewed the historical major events to hit the TEC service territory over the last 169 years. It is unclear whether climate change is affecting or will affect the frequency or severity of major storm events in the future. Research into this question reveals that there is no statistical evidence to support a higher frequency of major storm activity. The World Meteorological Organization provided the following comment:

> "Though there is evidence both for and against the existence of a detectable anthropogenic signal in the tropical cyclone climate record to date, no firm conclusion can be made on this point. However, research shows that there is evidence that the magnitude of the events are and will continue to increase."

Given this research, the Major Storm Event Database utilizes the historical probabilities for future storm probability. The impact of the events is discussed in the next section.

3.3 Major Storms Impact

Table 3-2 shows the damages cost of recent major storms to hit the Southeast United States. The table shows that the costs of these major events is significant.

Table 3-2: Recent Major Event Damages Cost

Storm Name	Category	Year	Damages (2018 $Billions)
Michael	5	2018	$25
Irma	4	2017	$51
Matthew	5	2016	$10
Wilma	3	2005	$10
Dennis	3	2005	$3
Jeanne	3	2004	$9
Ivan	3	2004	$19
Frances	2	2004	$12
Charley	4	2004	$19

The costs shown in the table are all damage costs to society and are based on insurance claims. The utility restoration costs are one element of this total. The TEC storm reports provide information on the restoration costs of historical events to hit the TEC service territory. Figure 3-11 provides a summary of the storm report for Hurricane Irma in 2017. It cost TEC approximately $100 million and restoration took slightly more than 7 days. Table 3-3 provides a summary of other recent TEC storm reports.

Figure 3-11: Hurricane Irma Impact to TEC Service Territory[8]

Storm Name: Irma

Year: 2017

TEC Cost: ~$100 million

Category: 1 over Florida

Radius: 50 Miles

Outage Duration: 7 Days

System Impact:
15 T-Lines
200 Circuits
55% of Customers

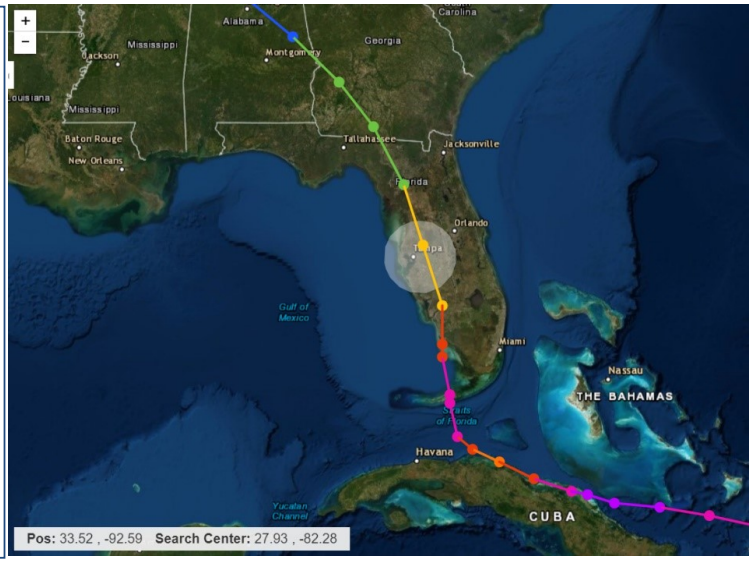


Table 3-3: Storm Report Summary

Storm Name	Category	Year	Damages (2018 $Millions)
Irma	1	2017	$102
Matthew	3	2016	$1
Hermine	1	2016	$6
Colin	TS	2016	$3

3.4 Major Storms Database

TEC and 1898 & Co collaborated in developing the Major Storm Events Database. The database utilizes the results of the NOAA analysis to identify 13 unique storm types. With the range of storm probabilities, the range in cost for each unique storm type, and the range in system impact, the 13 unique storm types are represented by 99 different storm events. Table 3-4 provides a summary of the Major Storms Event Database. The table includes the ranges of probabilities, restoration costs, impact to the system, and duration. Each of the 99 storm events are then modeled within the Storm Impact Model described more in the next section.

[8] See Footnote 2

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Table 3-4: Storm Event Database

Storm Type No	Scenario Name	Annual Probability	Restoration Costs (Millions)	System Impact (Laterals)	Total Duration (Days)
1	Cat 3+ Direct Hit - Gulf	1.0% - 2.0%	$306 - $1,224	60% - 70%	17.4 - 34.5
2	Cat 1 & 2 Direct Hit – Florida	5% - 8%	$76.5 - $153	35% - 55%	6.0 - 8.8
3	Cat 1 & 2 Direct Hit – Gulf	2% - 4%	$153 - $306	45% - 60%	8.7 - 12.9
4	TS Direct Hit	16.5%	$25.5 - $76.5	12.5% - 31.3%	2.6 - 5.3
5	TD Direct Hit	14.5%	$5.1 - $15.3	6.3% - 15.6%	2.0 - 3.6
6	Localized Event Direct Hit	50.0%	$0.5 - $1.5	1.3% - 3.1%	0.3 - 0.6
7	Cat 3+ Partial Hit	3% - 4%	$91.8 - $184	36% - 48%	6.4 - 9.2
8	Cat 1 & 2 Partial Hit	7.0%	$15.3 - $91.8	8.5% - 28%	2.3 - 6.9
9	TS Partial Hit	17% - 18%	$11.5 - $30.6	8% - 15%	2.0 - 3.6
10	TD Partial Hit	12% - 15%	$0.4 - $3.1	2% - 3.8%	1.5 - 2.7
11	Cat 3+ Peripheral Hit	2% - 3%	$0.8 - $ 22.2	1.2% - 14.1%	1.0 - 3.0
12	Cat 1 & 2 Peripheral Hit	10% - 11%	$0.6 - $8.9	0.9% - 6.5%	0.9 - 2.3
13	TS Peripheral Hit	11% - 12%	$0.5 - $3.8	0.7% - 3.4%	0.9 - 1.3

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4.0 STORM IMPACT MODEL

The second major component of the Storm Resilience Model is the Storm Impact Model. Whereas the Major Storms Event Database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for each storm stressor, the Storm Impact Model goes a layer deeper and develops the phases of resilience for each potential hardening project on the TEC T&D system for each storm stressor scenario.

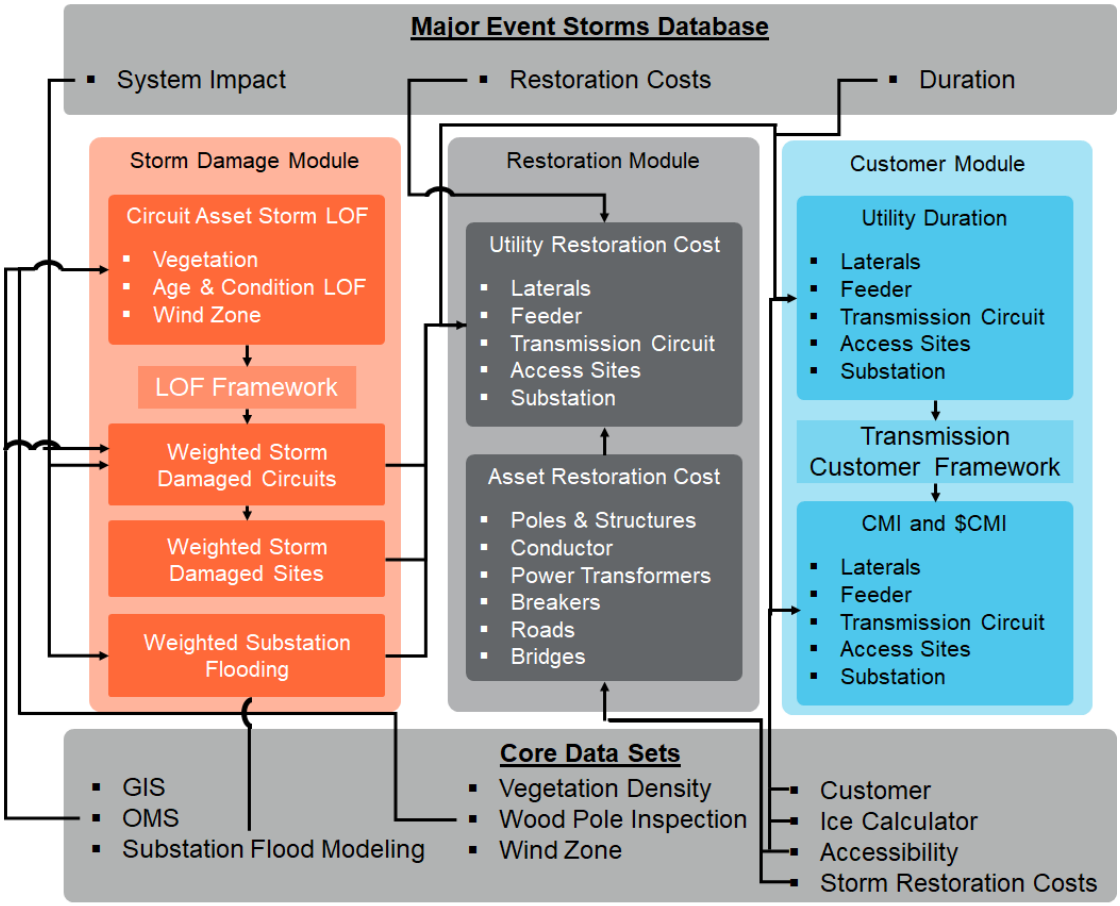
The Storm Impact Model models the impact to the system of any type of major storm event. Specifically, it identifies, from a weighted perspective, the particular laterals, feeders, transmission lines, access sites, and substations that fail for each type of storm in the Major Storms Event Database. The model also estimates the restoration costs associated with the specific sub-system failures and calculates the impact to customers in terms of CMI. Finally, the Storm Impact Model models each storm event for both a Status Quo and Hardened scenario. The Hardened scenario assumes the assets that make up each project have been hardened. The Storm Impact Model then calculates the benefit of each hardening project from a reduced restoration cost and CMI perspective.

The Storm Impact Model utilizes a robust and sophisticated set of data and algorithms to model the benefits of each hardening project for each storm scenario. This section of the report outlines the core data, algorithms, and frameworks that are part of the Storm Impact Model. It outlines a very granular level of analysis of the TEC System. This granular level of data and analysis allows for the Storm Resilience Model to accurately calculate the ratio of resilience benefit to cost resulting in more efficient hardening investment. This also provides confidence that investments are targeted to the portions of the system that provide the most value for customers.

Figure 4-1 provides an overview of the Storm Impact Model architecture. The following sections describe in more detail each of the core modules in more detail.

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Figure 4-1: Storm Impact Model Overview



4.1 Core Data Sets and Algorithms

As discussed above, the resilience-based approach and methodology is data driven. This section outlines the core data sets and base algorithms employed within the Storm Impact Model. TEC's data systems include a connectivity model that allows for the linkage of the three foundational data sets used in the Storm Impact Model – the Geographical Information System (GIS), the Outage Management System (OMS), and Customer Information.

4.1.1 Geographical Information System

The Geographic Information System (GIS) serves as the first of three foundational data sets for the Storm Impact Model. The GIS provides the list of assets in TEC's system and how they are connected to each other. Since the resilience-based approach is fundamentally an asset management bottom-up

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based methodology, it starts with the asset data, then rolls all the assets up to projects, and all projects up to programs, and finally the programs up to the Storm Protection Plan.

In alignment with this methodology, TEC utilized the connectivity in their GIS model to link each distribution voltage asset up to a lateral (fuse protection device) or feeder (breaker or recloser protection device). This provides a granular evaluation of the distribution system that allows projects to be created to target only portions of a circuit for resilience investment. Through this approach, TEC and 1898 & Co. were able to use the asset level information from Table 4-1 and convert it to the project level summaries in Table 4-2. It is important to note that each asset in Table 4-1 is tied to one of the projects listed in Table 4-2, which provides a bottom-up analysis.

Table 4-1: TEC Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**710**
Feeder Poles	[count]	58,700
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,300
Lateral OH Primary	[miles]	3,900
Transmission Circuits	**[count]**	**215**
Wood Poles	[count]	5,000
Steel / Concrete / Lattice Structures	[count]	20,400
Conductor	[miles]	1,300
Substations	[count]	**9**

Table 4-2: Projects Created from TEC Data Systems

Program	Project Count
Distribution Lateral Undergrounding	12,310
Transmission Asset Upgrades	107
Substation Extreme Weather Hardening	9
Distribution Overhead Feeder Hardening	930
Total	13,356

4.1.2 Outage Management System

The second foundational data set is the OMS. The OMS includes detailed outage information by cause code for each protection device over the last 20 years. The Storm Impact Model utilized this information to understand the historical storm related outages for the various distribution laterals and feeders on the system to include Major Event Days (MED), vegetation, lightening, and storm-based outages. The

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OMS served as the link between customer class information and the GIS to provide the Storm Impact Model with the information necessary to understand how many customers and what type of customers would be without service for each project. The OMS data also served as the foundation for calculating benefits for feeder automation projects. This is discussed in more detail in Section 5.4.

4.1.3 Customer Type Data

TEC provided customer count and type information that featured connectivity to the GIS and OMS. This allowed the Storm Impact Model to directly link the number and type of customers impacted to each project and the project's assets. For example, the Storm Impact Model 'knows' that if pole 'Y' fails, fuse '1' will operate causing XX customers to be without service. The model also knows what type of customers are served by each asset; residential, small or large commercial, small or large industrial, and priority customers. This customer information is included for every distribution asset in TEC system. The customer information is used within the Storm Impact Model to calculate the CMI (customers affected * outage duration) for each storm for each lateral or feeder project. Table 4-3 below shows the count of customers by class from TEC's service territory that have been linked to assets in the Storm Impact Model.

Table 4-3: Customer Counts by Type

Customer Type	Customer Count
Residential	695,000
Small Commercial and Industrial	71,200
Large Commercial and Industrial	16,300
Total	782,500

4.1.4 Vegetation Density Algorithm

The vegetation density for each overhead conductor is a core data set for identifying and prioritizing resilience investment for the circuit assets since vegetation blowing into conductor is the primary failure mode for major storm event for TEC. The Storm Impact Model calculates the vegetation density around each transmission and distribution overhead conductor. The Storm Impact Model utilizes tree canopy data to calculate the percentage of vegetation for 100 feet by 100 feet grids across the entire TEC system. The 100 square foot grid size is indicative of the vegetation density on the system from a major storm perspective. For each span of conductor (approximately 240,000) a vegetation density is assigned based on the grid the conductor goes through. This information is used within the LOF framework to identify the portions of the system mostly likely to have an outage for each type of storm.

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Figure 4-2 and Figure 4-3 show the range of vegetation density for OH Primary and Transmission Conductor, respectively. The figures rank the conductors from highest to lowest level of vegetation density. As shown in the figures, approximately 30 to 35 percent of the conductor spans (not weighted by length) for OH Primary and Transmission Conductor have near zero tree canopy coverage, while approximately 65 to 70 percent have some level of coverage all the way up to 100 percent coverage.

Figure 4-2: Vegetation Density on TEC Primary Conductor

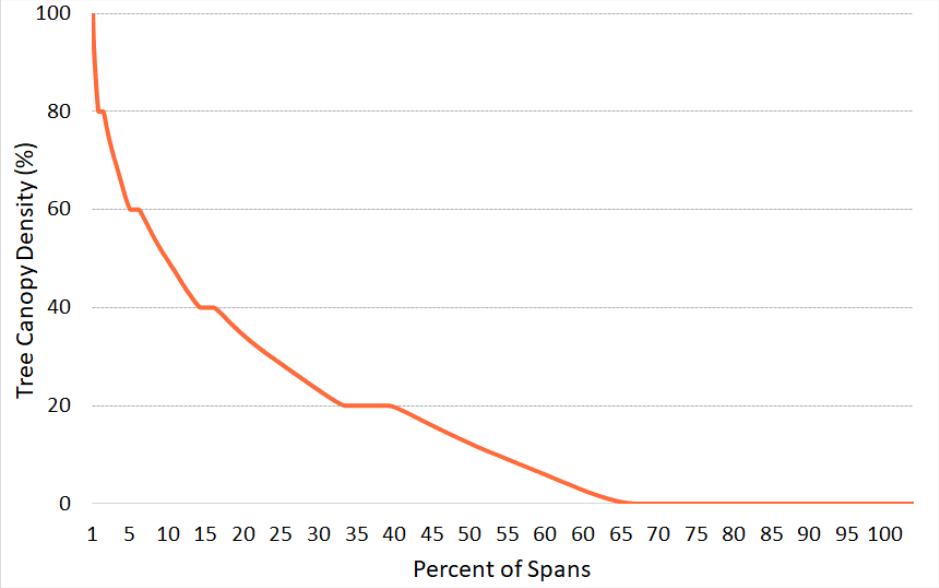
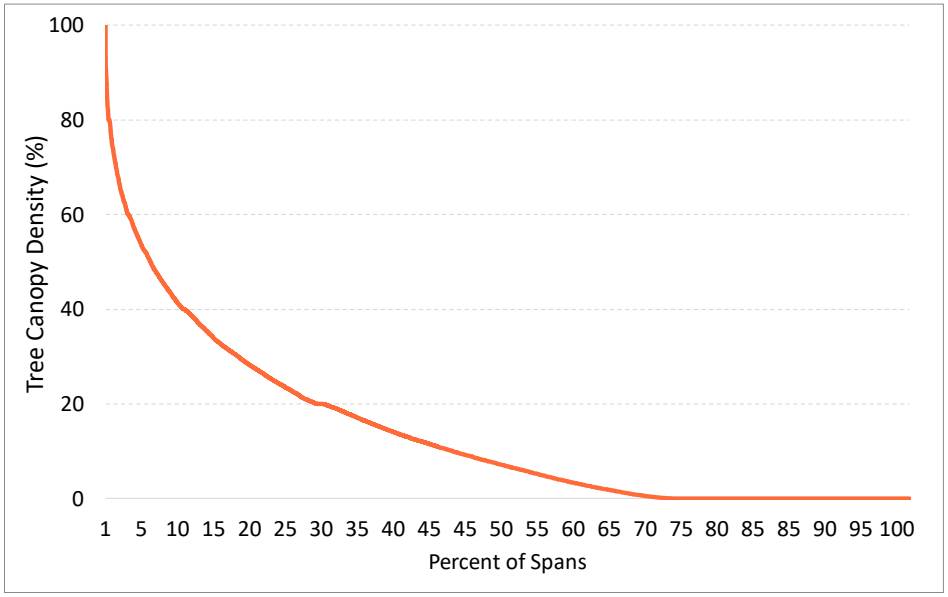


Figure 4-3: Vegetation Density on TEC Transmission Conductor

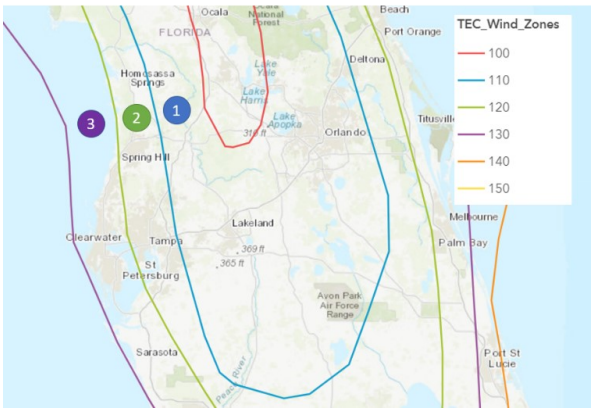


4.1.5 Wood Pole Inspection Data

A compromised, or semi-compromised, pole will fail at lower dynamic load levels then poles with their original design strength. The Storm Impact Model utilizes wood pole inspection data within 1898 & Co.'s asset health algorithm to calculate an Asset Health Index (AHI) and 'effective' age for each pole. Section 4.2.2 outlines the approach for using the 'effective' age for assets to calculate the age and condition based LOF.

4.1.6 Wind Zone

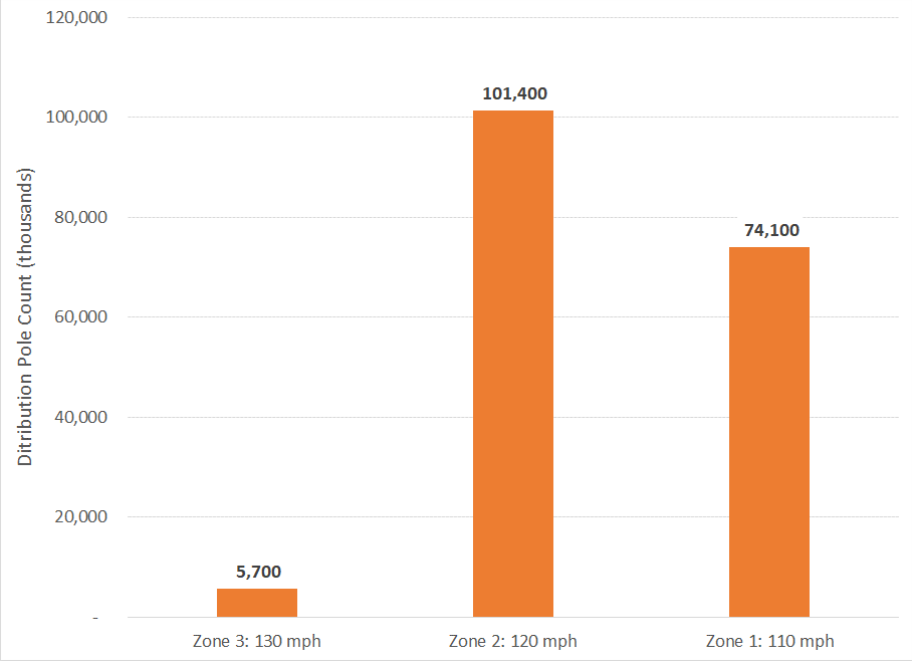
A third driver of storm-based failure is the asset's location with respect to wind speeds. Wind zones have been created across the United States for infrastructure design purposes. The National Electric Safety Code (NESC) provides wind and ice loading zones. The zones show that wind speeds are typically are higher closer to the coast and lower the further inland as shown in the adjacent figure. The Storm Impact Model utilizes the provided wind zone data from the public records



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and the asset geospatial location from GIS to designate the appropriate wind zone. Figure 4-4 shows distribution of assets within each wind zone. As shown in the figure, most of the poles are in the 120 mph and 110 mph zones, while a smaller percentage are in the 130 mph zone near the coast.

Figure 4-4: Pole Wind Zone Distribution



4.1.7 Accessibility

The accessibility of an asset has a tremendous impact on the duration of the outage and the cost to restore that part of the system. Rear lot poles take much longer to restore and cost more to restore than front lot poles. To take differences in accessibility into account, the Storm Impact Model performs a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access, others were designated as in the deep right-of-way (ROW). This designation was used to calculate restoration and hardening project costs in the Storm Impact Model. Approximately 60 percent of the T&D system has some kind of road access while the remainder, approximately 40 percent, is in the deep right-of-way.

4.1.8 ICE Calculator

To monetize the cost of a storm outage, the Storm Impact Model and Resilience Benefit Calculation utilize the ICE Calculator. The ICE Calculator is an electric reliability planning tool developed by Freeman,

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Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (DOE).

The Storm Impact Model includes the estimated storm interruption costs for residential, small commercial and industrial (C&I), and large C&I customers. The calculator was extrapolated for the longer outage durations from storm outages. The extrapolation includes diminishing costs as the storm duration extends. These estimates for outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level. The avoided monetized CMI and restoration cost benefit are used for prioritization of projects.

4.1.9 Substation Flood Modeling

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH models perform simulations to estimate surge heights above ground elevation for various storm types. The simulations are based on historical, hypothetical, and predicted hurricanes. The model uses a set of physics equations applied to the specific location shoreline, Tampa in this case, incorporating the unique bay and river configurations, water depths, bridges, roads, levees, and other physical features to establish surge height. These results are simulated several thousand times to develop the Maximum of the Maximum Envelope of Water, the worst-case scenario for each storm category. The SLOSH model results were overlaid with the location of TEC's 216 substations to estimate the height of above the ground elevation for storm surge. The SLOSH model identified 59 substations with flooding risk depending on the hurricane category Based on TEC's more detailed assessment 9 substations were identified that included flooding risk to the level that could justify investment.

4.2 Weighted Storm Likelihood of Failure Module

The Weighted Storm LOF Module of the Storm Impact Model identifies the parts of the system that are likely to fail given the specific storm loaded from the Major Storms Event Database. The module is grounded in the primary failure mode of the asset base; storm surge and associated flooding for substations and wind, asset condition, and vegetation for circuit assets.

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4.2.1 Substation Storm Likelihood of Failure

The main driver of substation failures during major storm events is flooding. The Major Storms Event Database designates the number of substations expected to have minor and major flooding for each of the 99 storm scenarios. Only the storm scenarios with hurricanes coming from the Gulf of Mexico provide the necessary condition for storm surge that would cause substation flooding.

To identify which substations would be the likely to experience flooding, the Storm Impact Model uses the substation flood modeling described in Section 4.1.9. This model provides the estimated feet of flooding above site elevation assuming the maximum of maximum approach, a worst of the worst-case scenario. Because of this extreme worst-case scenario, the results could not be used for a typical hurricane category to hit the TEC service territory. The flood modeling has flood height data for all 5 hurricane category types. The Storm Impact Model uses the flooding height values as likelihood scores to identify the substation Probability of Failure (POF) for each storm event in the Major Storms Event Database.

4.2.2 Circuits Storm Likelihood of Failure

The main driver of circuit failures during storms is wind blowing vegetation (and other debris) into conductor. The conductor is weighted down. The additional weight, when combined with the wind loading, causes the structures holding up the conductor to fail. Typically, the vegetation touching the conductor triggers the protection device to operate, however, the enhanced loading on the poles causes asset failures that are costly to repair both in terms of restoration costs and in CMI. The storm LOF of an overhead distribution asset is a function of the vegetation around it, the age and condition of the asset, and the applicable wind zone (coastal zones see higher wind speeds).

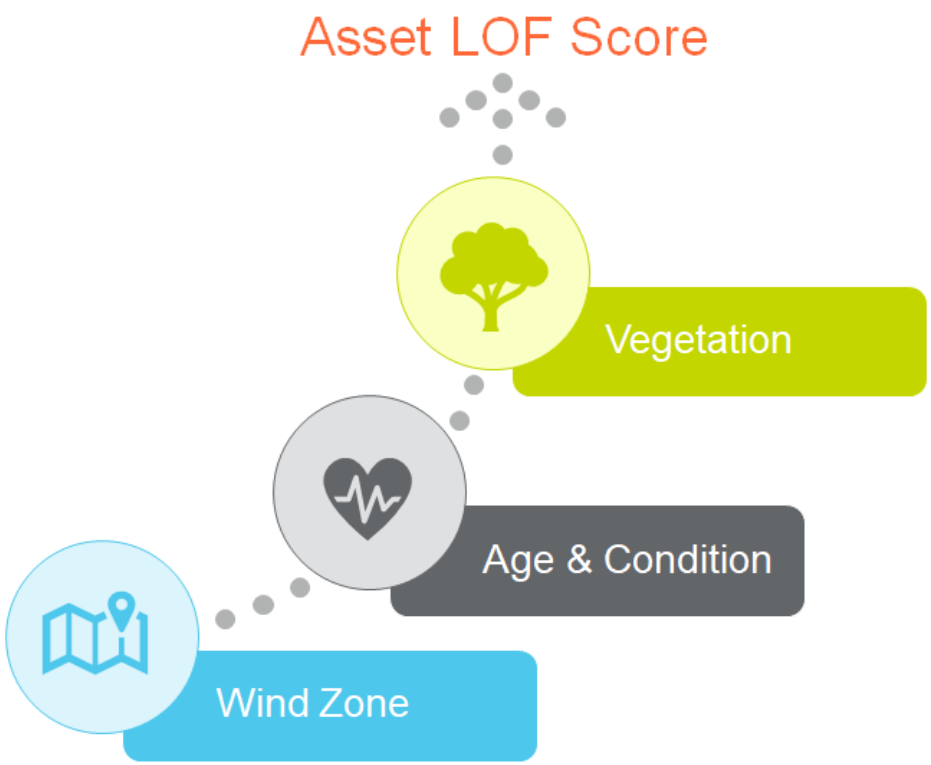
Figure 4-5 depicts the framework used to calculate the storm LOF score for each circuit asset on TEC's T&D system. Assets included within the framework are: wood poles, steel poles, concrete poles, lattice towers, overhead primary, and overhead transmission conductor. The framework does not use weightings, rather it is normalized across each of the scoring criteria.

For the vegetation LOF scores, the Storm Impact Model uses the vegetation density of each overhead primary and transmission conductor normalized for length. Section 4.1.4 outlines the approach to estimate the vegetation density for approximately 240,000 primary and transmission conductors. Each primary and transmission conductor is one span from structure to structure. The vegetation density,

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normalized for length, is used in the LOF framework to calculate an LOF score for vegetation. Overall, the vegetation score contributes on average 60 to 80 percent of system LOF depending on the storm scenario.

Figure 4-5: Storm LOF Framework for Circuit Assets

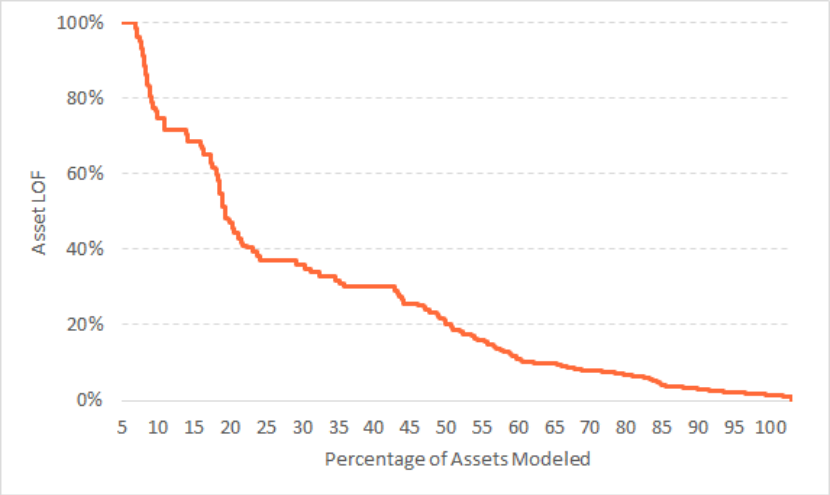


The Storm Impact Model utilizes 1898 & Co.'s asset management solution, Capital Asset Planning Solution (CAPS), to estimate the age and condition based LOF for each wood pole, metal structure, overhead primary, and transmission conductor. 1898 & Co.'s CAPS utilizes industry standard survivor curves with an asset class expected average service life and the asset's 'effective' age (or calendar age if condition data is not available) to estimate the age and condition based LOF over the next 10 years. Condition data for wood poles was used to factor in any rot or impacts to the pole's ground-line circumference. Section 4.1.5 outlines the wood pole inspection data used in the 'effective' age calculations.

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Figure 4-6 shows the age and condition LOF distribution of the T&D infrastructure asset base. The age and condition based LOF scores were used in the storm LOF framework to calculate storm LOF scores for each asset. Overall, the age and condition score contribute on average 20 to 30 percent of system LOF depending on the storm scenario.

Figure 4-6: Age & Condition LOF Distribution



The wind zone criteria use the wind zone designation data from Section 4.1.6 inside the asset LOF framework to develop the LOF scores. Overall, the wind zone contributes on average 5 to 10 percent of system LOF depending on the storm scenario.

The Storm Impact Model uses the sum of the three criteria (vegetation, age & condition, and wind zone) to calculate the total storm LOF for each asset. The assets are then totaled up to the project level, providing a granular understanding of the LOF for each project. The Storm Impact Model uses the storm LOF scores to identify the circuit project POF for each storm event in the Major Storms Event Database.

4.2.3 Site Access Storm Likelihood of Failure

The site access dataset includes a hierarchy of the impacted circuits. Using this hierarchy, each site access LOF equals the total of the circuits it provides access to. Section 4.2.2, above, provides the details on how the circuit LOF is calculated.

4.3 Project & Asset Reactive Storm Restoration

The Storm Impact Model estimates the cost to repair assets from a storm-based failure. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles,

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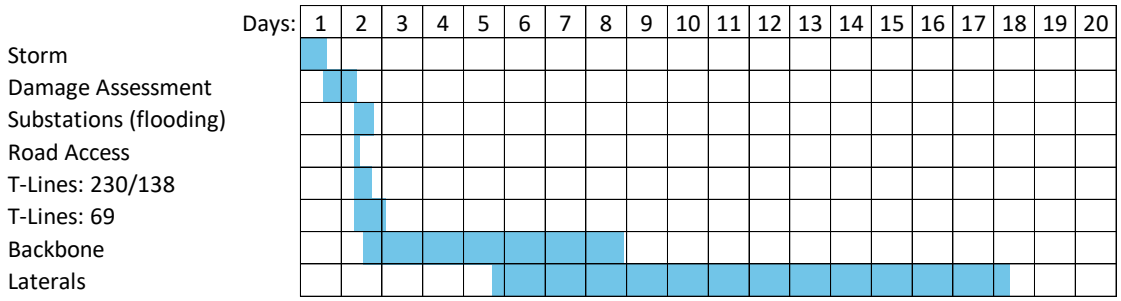
overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were based on storm restoration costs multipliers above planned replacement costs. The multipliers were in the 1.4 to 4.0 range. These multipliers were developed by TEC and 1898 & Co. collaboratively. They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms. Substation restoration costs include storm costs for minor and major flooding events. For minor flooding events, the substation equipment can be used in the short term to restore power flow after cleaning, but the equipment needs to be replaced within 1 year. For major flooding, the substation equipment cannot be restored and must all be replaced. Restoration costs for site access projects were developed by TEC and provided to 1898 & Co.

For each storm event, the restoration costs at the asset level are aggregated up the project level and then weighted based on the project LOF (Section 4.2) and the overall restoration costs for the storm event outlined in the Major Event Storms Database.

4.4 Duration and Customer Impact

The Storm Impact Model calculates the duration to restore each project in the Status Quo Scenario. The assumptions for major asset class outage duration are outlined in the Major Event Storms Database. Figure 4-7 provides an example duration profile for the Category 3 and above storm event.

Figure 4-7: Example Storm Duration Profile



The project specific duration is based on percent complete vs percent time curves for each major asset class. The projects are ranked by metrics that are similar to those TEC uses to prioritize storm restoration activity, such as priority customers. Specific project durations are calculated based on completion vs time curves. For example, using the example from the figure above, a lateral project may have a relatively high priority (i.e. customer count is high with more critical customers). That lateral

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would be restored by day 7 of the profile above. However, the lowest ranked laterals will have project durations in the 16 to 17-day range.

The project duration is then multiplied by the number of affected customers for each project (see Section 4.1.3) to calculate the CMI for each project. It should be noted that the Storm Impact Model assumes feeder automation has been installed on each circuit so that the affected number of customers is 350, the target for each hardening protection zone. This is a conservative assumption so that no double counting of benefits occurs.

Some of the storm scenarios include significant outages to the transmission system. The percentage of the system impacted is so high that the designed resilience (looping) of the system is lost for a short period of time, which in turn causes mass customer outages across the system from the transmission system. The Storm Impact Model allocates customer outages from these events to the various parts of the TEC transmission system based on transmission system operating capacity and overall importance to the Bulk Electric System (BES).

Finally, the CMI for each project for each storm event is monetized using the ICE Calculator. Section 4.1.8 provides additional detail on the ICE Calculator. The monetization is performed for each type of customer; residential, small C&I, large C&I, and the various priority customers. The monetization of CMI is calculated for project prioritization purposes as discussed below in Section 5.0.

4.5 'Status Quo' and Hardening Scenarios

The Storm Impact Model calculates the storm restoration costs and CMI for the 'Status Quo' and Hardening Scenarios for each project by each of the 99 storm events. The delta between the two scenarios is the benefit for each project. This is calculated for each storm event based on the change to the core assumptions (vegetation density, age & condition, wind zone, flood level, restoration costs, duration, and customers impacted) for each project.

The output from the Storm Impact Model is a project by project probability-weighted estimate of annual storm restoration costs, annual CMI, and annual monetized CMI for both the 'Status Quo' and Hardened Scenarios for all 99 major storm scenarios. The following section describes the methodology utilized to model all 99 major storms and calculate the resilience benefit of each project.

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5.0 RESILIENCE NET BENEFIT CALCULATION MODULE

The Resilience Benefit Calculation Module of the Storm Resilience Model uses the annual benefit results of the Storm Impact Model and the estimated project costs to calculate the net benefits for each project. Since the benefits for each project are dependent on the type and frequency of major storm activity, the Resilience Benefit Module utilizes stochastic modeling, or Monte Carlo Simulation, to randomly select a thousand future worlds of major storm events to calculate the range of both 'Status Quo' and Hardened restoration costs and CMI. The benefit calculation is performed over a 50-year time horizon, matching the expected life of hardening projects.

The feeder automation hardening project resilience benefit calculation employs a different methodology given the nature of the project and the data available to calculate benefits. The Outage Management System (OMS) includes 20 years of historical data. The resilience benefit is based on the expected decrease in impacted customers if the automation had been in place.

The following sections provide additional detail on the project costs, Monte Carlo Simulation, and feeder automation.

5.1 Economic Assumptions

The resilience net benefit calculation includes the following economic assumptions:

- Period: 50 years – most of the hardening infrastructure will have an average service life of 50 or more years
- Escalation Rate: 2 percent
- Discount Rate: 6 percent

5.2 Project Cost

Project costs were estimated for the over 20,000 projects in the Storm Resilience Model. Some of the project costs were provided by TEC while others were estimated using the data within the Storm Resilience Model to estimate scope (asset counts and lengths) that was then multiplied by unit cost estimates to calculate the project costs. The following sub-sections outline the approach to calculate project costs for each of the programs.

5.2.1 Distribution Lateral Undergrounding Project Costs

For each project, the GIS (see Section 4.1.1) and Accessibility algorithm (see Section 4.1.7) were leveraged to estimate:

- Miles of overhead conductor for 1, 2, and 3 phase laterals
- Number of overhead line transformers, including number of phases, that need to be converted to pad mounted transformers
- Number of meters connected through the secondary via overhead line.

Each of these values creates the scope for each of the projects. TEC provided unit costs estimates, which are multiplied by the scope activity (asset counts and lengths) to calculate the project cost. The unit cost estimates are based on supplier information and previous undergrounding projects.

5.2.2 Transmission Asset Upgrades Project Costs

The Transmission Asset Upgrades program project costs are based on the number of wood poles by class, type (H-Frame vs monopole), and circuit voltage. TEC provided unit cost estimates for each type of pole to be replaced. The project costs equal the number wood poles on the circuit multiplied by the unit replacement costs.

5.2.3 Substation Extreme Weather Hardening Project Costs

The project costs for the Substation Extreme Weather Hardening program are based on the perimeter of each substation multiplied by the unit cost per foot to install storm surge walls. The costs per foot vary by the required height of the wall. The substation wall height is based off the needed height to mitigate the flooding from the SLOSH model results.

5.2.4 Distribution Overhead Feeder Hardening Project Costs

The distribution overhead feeder hardening project costs are based on the number of wood poles that don't meet current design standards for storm hardening and the cost to include automation. TEC provided unit replacement costs based on the accessibility of the pole as well as the average cost to add automation to each circuit.

5.2.5 Transmission Access Enhancements

TEC provided all the project costs for the Transmission Access Enhancements. The cost estimates were based on the length of the bridge or road. Those lengths were developed using geospatial solutions using TEC's GIS for each problem area.

5.3 Resilience-weighted Life-Cycle Benefit

The benefits of storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type (e.g. Category 1 from the Gulf) has a range of potential probabilities and consequences. For this reason, the Storm Resilience Model employs stochastic modeling, or Monte Carlo Simulation. Monte Carlo Simulation is a random sampling methodology.

In the context of the Storm Resilience Model, the Monte Carlo simulator selects the major storm events to impact the TEC service territory over the next 50 years from the Major Storms Event Database (Section 3.0). That database outlines the 'universe' of storm event types that could impact the TEC service territory. The database includes 13 unique storm types with 99 different storm events when factoring in the range of probabilities and impacts. The database is based on a historical analysis of major storms to come within 150 miles of the TEC service territory over the last 169 years.

Table 5-1 shows the selection of storm events for each storm type for the first 7 iterations and iteration 1,000. The selected 13 storm events for each iteration represent the future world of storms to impact the TEC service territory over the next 50 years. Each storm has a different frequency and impact to the TEC system. The Monte Carlo Simulation is performed over 1,000 iterations creating a 1,000 of these future storm 'worlds'.

Each project's CMI, monetized CMI, and restoration costs are calculated for the 13 storm events for each iteration for both the 'Status Quo' and Hardened Scenarios over a 50-year time horizon. The difference between the 'Status Quo' and Hardened Scenarios is the benefit of the project for that storm event. The sum of the benefits for all 13 storm events for each iteration equals the total benefits for the project. The CMI, monetized CMI, and restoration costs are then weighted by the probability of the storm event to calculate the storm resilience-weighted life-cycle benefit.

Table 5-1: Monte Carlo Simulation Storm Event Selection

Storm Type No	Scenario Name	Storm Event - Iteration								
		1	2	3	4	5	6	7	...	1000
1	Cat 3+ Direct Hit - Gulf	5	6	5	2	3	6	1	...	3
2	Cat 1 & 2 Direct Hit – Florida	13	16	11	11	8	17	12	...	17
3	Cat 1 & 2 Direct Hit – Gulf	20	24	20	19	19	20	23	...	20
4	TS Direct Hit	28	29	29	30	29	29	30	...	29
5	TD Direct Hit	31	32	31	32	33	31	33	...	31
6	Localized Event Direct Hit	36	35	34	35	36	34	35	...	34
7	Cat 3+ Partial Hit	39	39	39	39	40	37	37	...	41
8	Cat 1 & 2 Partial Hit	43	45	46	43	43	48	45	...	43
9	TS Partial Hit	50	52	52	52	50	54	52	...	50
10	TD Partial Hit	62	61	56	58	61	59	59	...	62
11	Cat 3+ Peripheral Hit	74	72	72	72	71	70	72	...	70
12	Cat 1 & 2 Peripheral Hit	82	87	87	76	79	84	81	...	82
13	TS Peripheral Hit	99	92	98	90	92	93	95	...	88

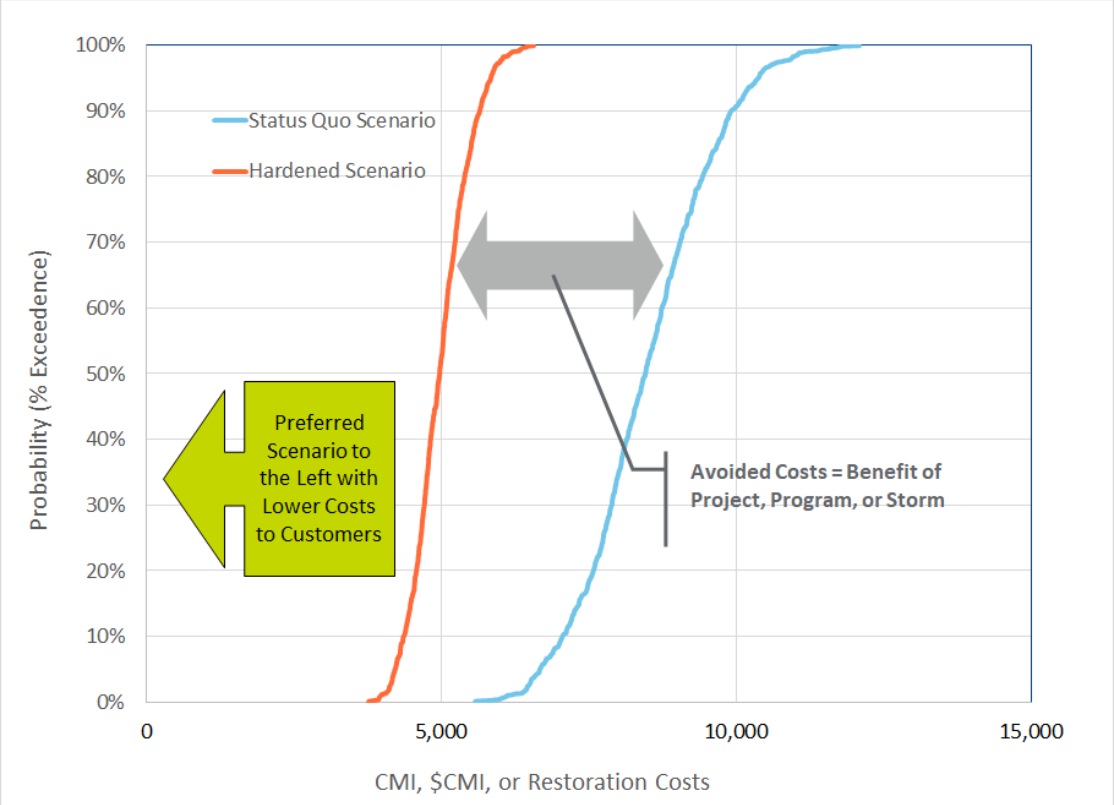
Table 5-2 provides an example calculation of storm resilience weighted CMI, monetized CMI, and restoration costs for both the 'Status Quo' and Hardened Scenarios. Each of the values is weighted by the probability of the event from the storms database over the 50-year time horizon. The monetized CMI and restoration cost show the NPV of the 50-year storm probability adjusted cash flows. The delta between the 'Status Quo' and Hardened scenarios is the benefits of the project for the first iteration. The example shows that the project is not impacted by small or peripheral storms. This calculation is repeated for all 1,000 iterations for the over 20,000 projects in the Storm Resilience Model.

Table 5-2: Project CMI and Restoration Cost Example – Iteration 1

Storm Type No	Scenario Name	Status Quo			Hardened		
		CMI	$CMI	Rest$	CMI	$CMI	Rest$
1	Cat 3+ Direct Hit – Gulf	64,910	$606,664	$132,303	41,947	$392,045	$0
2	Cat 1 & 2 Direct Hit – Florida	26,001	$377,198	$38,694	16,803	$243,757	$0
3	Cat 1 & 2 Direct Hit – Gulf	22,228	$305,395	$38,078	14,364	$197,356	$0
4	TS Direct Hit	26,587	$471,815	$53,821	17,072	$302,952	$43,127
5	TD Direct Hit	9,612	$150,651	$9,619	6,172	$96,733	$7,708
6	Localized Event Direct Hit	1,282	$27,601	$4,858	823	$17,723	$3,893
7	Cat 3+ Partial Hit	5,975	$86,440	$12,779	3,862	$55,860	$0
8	Cat 1 & 2 Partial Hit	3,575	$58,056	$14,771	2,310	$37,517	$0
9	TS Partial Hit	1,077	$27,788	$6,303	691	$17,843	$5,051
10	TD Partial Hit	$0	$0	$0	$0	$0	$0
11	Cat 3+ Peripheral Hit	$0	$0	$0	$0	$0	$0
12	Cat 1 & 2 Peripheral Hit	$0	$0	$0	$0	$0	$0
13	TS Peripheral Hit	$0	$0	$0	$0	$0	$0
	Total	161,246	$2,111,610	$311,225	104,043	$1,361,786	$59,779

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. Figure 5-1 shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios. The resilience benefit of the project, program, or plan is the gap between the S-curves for the top part of the curve. Section 2.4 describes this in further detail.

Figure 5-1: Status Quo and Hardened Results Distribution Example



5.4 Feeder Automation Benefits Calculation

As part of the Storm Protection Plan, TEC intends to include feeder automation to allow for automatic switching during storm events. The design standard is to limit outages to impact a maximum of 350 customers. While many of the other Storm Protection Programs provide resilience benefit by mitigating outages from the beginning, feeder automation projects provide resilience benefit by decreasing the impact of a storm event, the 'pit' of the resilience conceptual model described in Figure 2-2 above.

The resilience benefit for feeder automation was estimated using historical Major Event Day (MED) outage data from the OMS (see Section 4.1.2). TEC has outage records going back 20 years. The analysis assumes that future MED outages for the next 50 years will be similar to the last 20 years.

The outage records document all outages by protection device. The system includes customer relationship information for each protection device to calculate the number of customers impacted if a device operates. The OMS records the start and end times for each outage. The information from the

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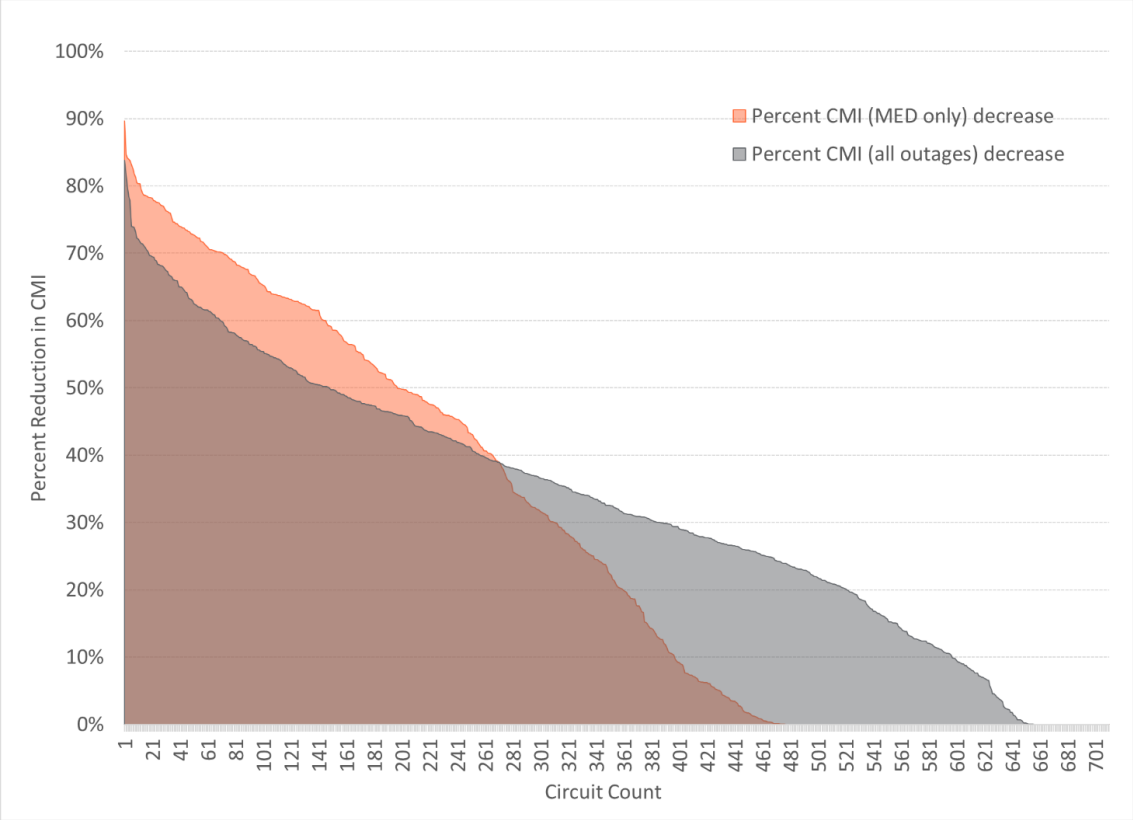
OMS is used to calculate reliability metrics for reporting purposes. The OMS also includes designations for MED, which are days during which a significant part of the system is impacted by a major event. These are typically major storms. MED is often referred to as 'grey-sky' days as opposed to non-MED which is referenced as 'blue-sky' days.

For the resilience benefit calculation, the Storm Resilience Model re-calculates the number of customers impacted by an outage, assuming that feeder automation had been in place. For example, a historical outage may have included a down pole from a storm event, causing the substation breaker to lock out and resulting in a four-hour outage for 1,500 customers, or 360,000 CMI. The Storm Resilience Model re-calculates the outages as 350 customers without power for four hours, or 96,000 CMI. That example provides a reduction in CMI of over 70 percent. The Storm Resilience Model extrapolates the 19 years of benefit calculation to 50 years to match the time horizon of the other projects.

The feeder automation projects include a range of investment types including reclosers, poles, re-conductoring, adding tie lines, and substation upgrades to handle the load transfer. TEC provided the itemized costs for feeder automation for projects installed in years 2020 and 2021, and expected average feeder costs for years 2022 through 2029.

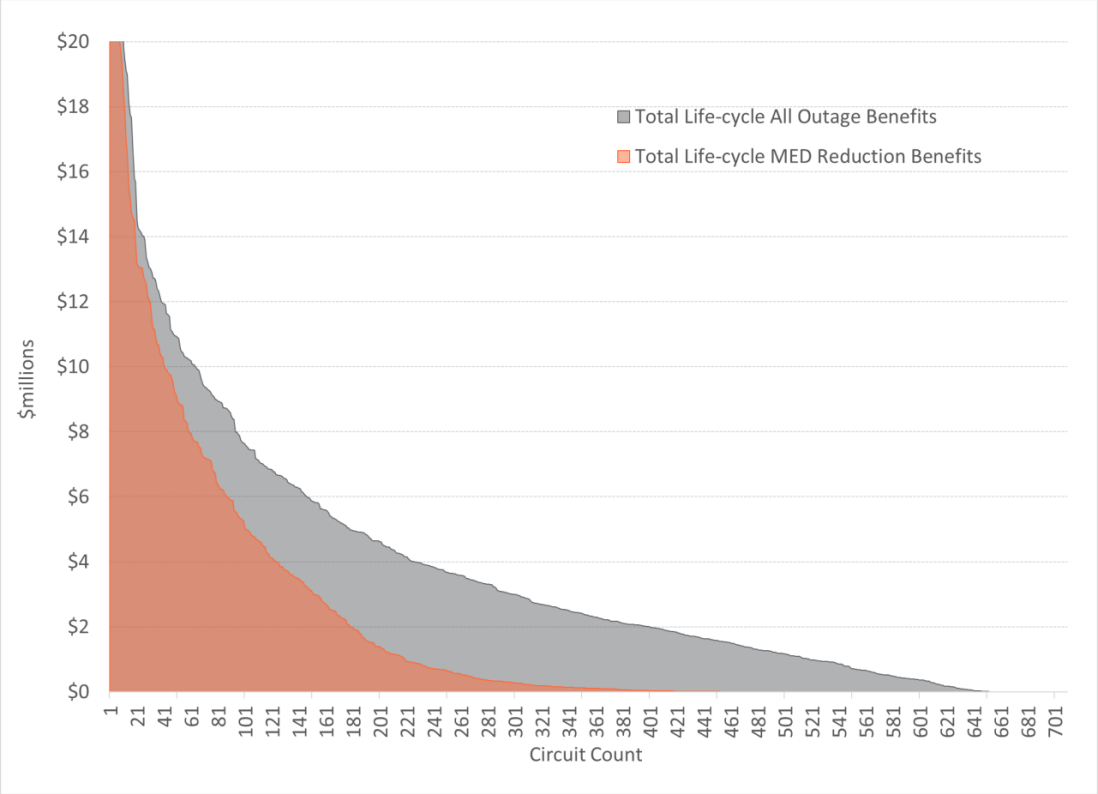
Figure 5-2 shows the percent decrease in CMI using this approach for all circuits. The figure is ranked from highest to lowest from left to right. The figure also includes the benefits to all outages. The figure shows a wide range of decreased CMI percentages with nearly 40 percent of circuits resulting in a 40 percent or more decrease in MED CMI. Additionally, the figure shows that approximately two thirds of the circuits would decrease MED CMI.

Figure 5-2: Automation Hardening Percent CMI Decrease



The resilience benefit calculation also monetized the CMI decrease using the ICE Calculator (Section 4.1.8). Figure 5-3 shows the percent decrease in monetized CMI for each circuit. The CMI was monetized and discounted over the 50-year time horizon to calculate the NPV. The NPV calculation assumed a replacement of the reclosers in year 25; the rest of the feeder automation investment has an expected life of 50 years or more. The monetization and discounted cash flow methodology was performed for project prioritization purposes.

Figure 5-3: Automation Hardening Monetization of CMI Decrease



6.0 BUDGET OPTIMIZATION AND PROJECT SELECTION

The Storm Resilience Model models consistently models the benefits of all potential hardening projects for an 'apples to apples' comparison. Sections 3.0, 4.0, and 5.0 described the approach and methodology to calculate the resilience benefit for the over 13,500 projects. Resilience benefit values include:

- CMI 50-year Benefit
- Restoration Cost 50-year NPV Benefit
- Life-cycle 50 year NPV gross Benefit (monetized CMI benefit + restoration cost benefit)
- Life-cycle 50 year NPV net Benefit (monetized CMI benefit + restoration cost benefit – project costs)

Each of these values includes a distribution of results from the 1,000 iterations. For ease of understanding and in alignment with the resilience base strategy, the approach focuses on the P50 and above values, specifically considering:

- P50 – Average Storm Future
- P75 – High Storm Future
- P95 – Extreme Storm Future

The following sections discuss the prioritization metric, budget optimization, and approach to developing the Storm Protection Plan.

6.1 Prioritization Metric - Benefit Cost Ratio

With all the projects being evaluated on a consistent basis, they can all be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life-cycle 50 year NPV gross benefit value listed above. The ranking is performed for each of the P-values listed above (P50, P75, and P95) as well as a weighted value.

Performing prioritization for the four benefit cost ratios is important since each project has a different slope in their benefits from P50 to P95. For instance, many of the lateral undergrounding projects have the same benefit at P50 as they do at P95. Alternatively, many of the transmission asset hardening projects are minorly beneficial at P50 but have significant benefits at P75 and even more at P95. TEC and 1898 & Co. settled on a weighting on the three values for the base prioritization metric, however,

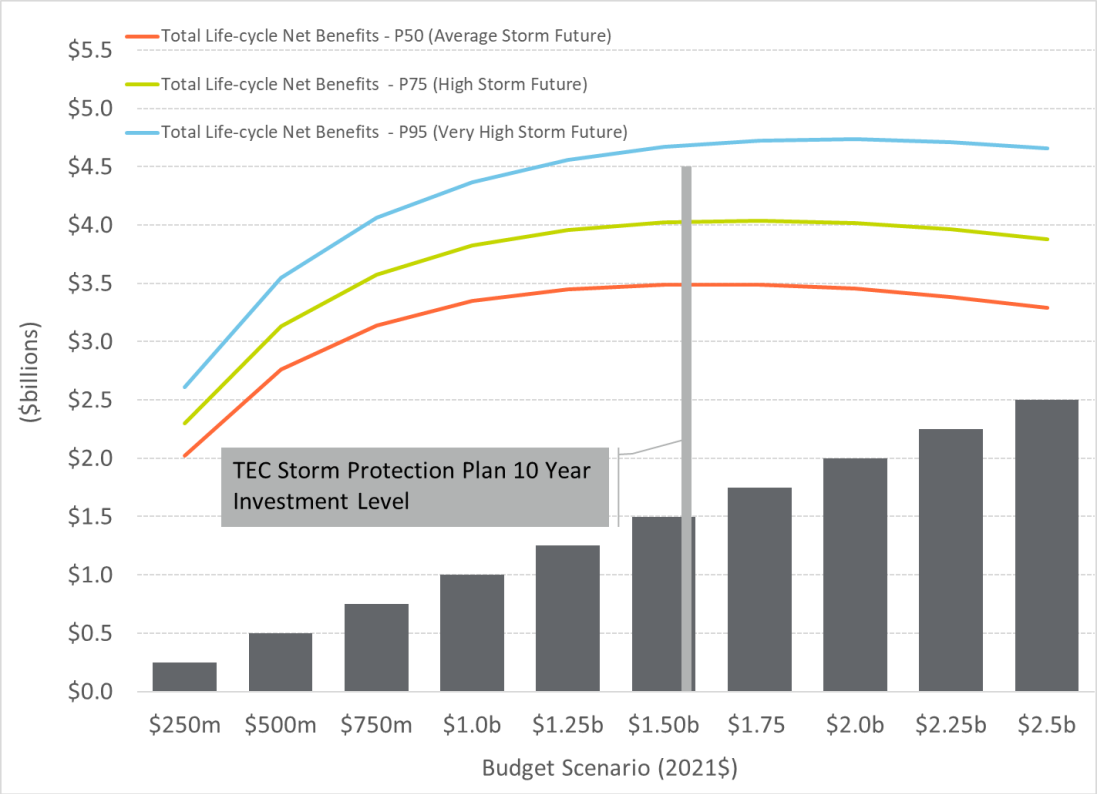
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investment allocations are adjusted for some of the programs where benefits are small at P50 but significant at P75 and P95.

6.2 Budget Optimization

The Storm Resilience Model performs project prioritization across a range of budget levels to identify the appropriate level of resilience investment. The goal is to identify where 'low hanging' resilience investment exists and where the point of diminishing returns occurs. Given the total level of potential investment the budget optimization analysis was performed in $250 million increments up to $2.5 billion. Figure 6-1 shows the results of the budget optimization analysis. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95.

Figure 6-1: Budget Optimization Results



The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2021 dollars for the TEC Storm Protection

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Plan. The TEC overall investment level is right before the point of diminishing returns showing that TEC's plan has an appropriate level of investment capturing the hardening projects that provide the most value to customers.

6.3 Storm Protection Plan Project Prioritization

In developing TEC's Storm Protection Plan, TEC and 1898 & Co. used the Storm Resilience Model as a tool for developing the overall budget level and the budget levels for each category. It is important to note that the Storm Resilience Model is only a tool to enable more informed decision making. While the Storm Resilience Model employs a data-driven decision-making approach with robust set of algorithms at a granular asset and project level, it is limited by the availability and quality of assumptions. In developing the TEC Storm Protection plan project identification and schedule, the TEC and 1898 & Co team factored in the following:

- Resilience benefit cost ratio including the weighted, P50, P75, and P95 values.
- Internal and external resources available to execute investment by program and by year.
- Lead time for engineering, procurement, and construction
- Transmission outage and other agency coordination.
- Asset bundling into projects for work efficiencies.
- Project coordination (i.e. project A before project B, project Y and project Z at the same time).

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7.0 RESULTS & CONCLUSIONS

TEC and 1898 & Co. utilized a resilience-based planning approach to identify and prioritize resilience investment in the T&D system. This section presents the costs and benefits of TEC's Storm Protection Plan. Customer benefits are shown in terms of the:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as CMI

7.1 Storm Protection Plan

This section includes the program capital investment and resilience benefit results for TEC's Storm Protection Plan.

7.1.1 Investment Profile

Table 7-1 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.59 billion. Lateral undergrounding makes up most of the total, accounting for 67.6 percent of the total investment. Feeder Hardening is second, accounting for 20.0 percent. Transmission upgrades make up 8.8 percent of the total, with substations and site access making up 1.7 percent and 2.0 percent, respectively.

Table 7-1: Storm Protection Plan Investment Profile by Program (Nominal $000)

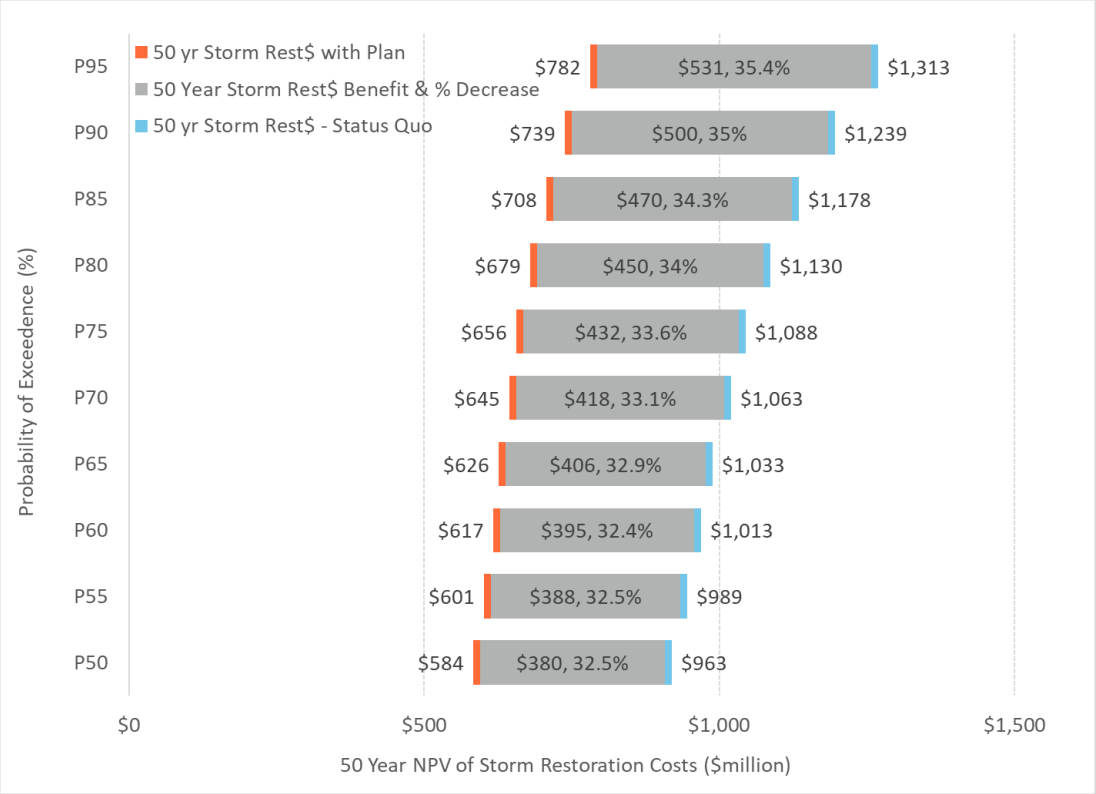
Year	Lateral Undergrounding	Transmission Asset Upgrades	Substation Hardening	Feeder Hardening	Transmission Site Access	Total
2022	$105,600	$16,500	$-	$33,300	$2,400	$157,800
2023	$104,500	$17,500	$700	$29,900	$3,000	$155,600
2024	$105,700	$17,500	$4,300	$30,000	$3,000	$160,500
2025	$105,100	$17,900	$2,700	$30,000	$3,700	$159,400
2026	$105,000	$18,200	$3,300	$30,000	$3,400	$159,900
2027	$105,600	$16,900	$2,900	$30,000	$3,400	$158,800
2028	$105,600	$17,300	$4,800	$30,000	$3,100	$160,800
2029	$105,600	$17,200	$700	$30,000	$2,800	$156,300
2030	$115,400	$-	$7,200	$37,000	$2,000	$161,600
2031	$115,400	$-	$900	$37,000	$4,400	$157,700
Total	$1,073,500	$139,000	$27,500	$317,200	$31,200	$1,594,700

7.1.2 Restoration Cost Reduction

Figure 7-1 shows the range in restoration cost reduction at various probability of exceedance levels. As a refresher, the P50 to P65 level represents a future world in which storm frequency and impact are close to average, the P70 to P85 level represents a future world where storms are more frequent and intense, and the P90 and P95 levels represent a future world where storm frequency and impact are all high.

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Figure 7-1: Storm Protection Plan Restoration Cost Benefit

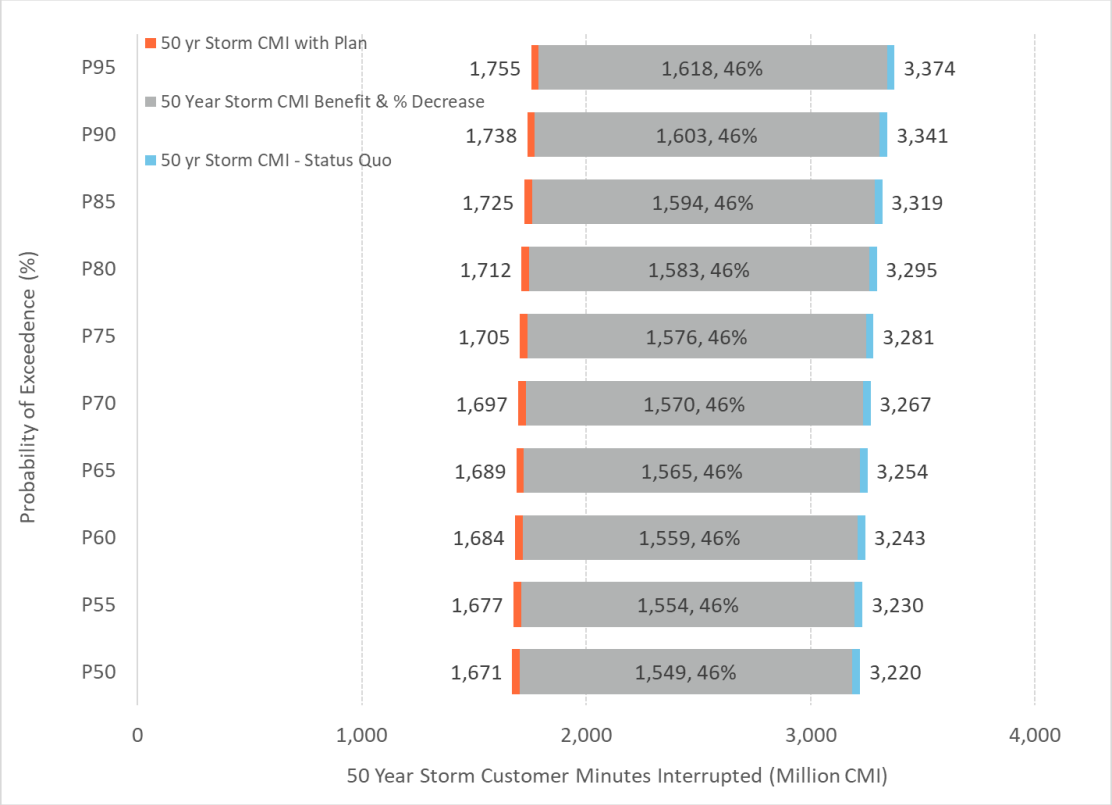


The figure shows that the 50 NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $960 million to $1,310 million. With the Storm Protection Plan, the costs decrease by approximately 33 to 35 percent. The decrease in restoration costs is approximately $380 to $530 million. From an NPV perspective, the restoration costs decrease benefit is approximately 24 to 33 percent of the project costs.

7.1.3 Customer Benefit

Figure 7-2 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 46 percent decrease in the storm CMI over the next 50 years.

Figure 7-2: Storm Protection Plan Customer Benefit



7.2 Program Investment Profile Details

Table 7-3, Table 7-4, Table 7-5, and Table 7-6 show annual investment for the five programs evaluated in the Storm Resilience Model. The tables also show the counts associated with the investment level. For Table 7-3 the total count of circuits being worked on each year is shown. Several circuits are worked on over multiple years. The plan includes upgrading assets on 97 different circuits.

Table 7-2: Distribution Lateral Undergrounding Investment Profile

Year	Lateral Count	Miles	Nominal Cost ($000)
2022	225	76	$105,600
2023	268	83	$104,500
2024	436	108	$105,700
2025	538	111	$105,100
2026	471	110	$105,000
2027	426	107	$105,600
2028	443	112	$105,600
2029	389	106	$105,600
2030	436	123	$115,400
2031	502	143	$115,400
Total	4,134	1,079	$1,073,500

Table 7-3: Transmission Asset Upgrades Investment Profile

Year	Circuits Worked On	Nominal Cost ($000)
2022	37	$16,500
2023	26	$17,500
2024	10	$17,500
2025	10	$17,900
2026	5	$18,200
2027	11	$16,900
2028	14	$17,300
2029	24	$17,200
2030	0	$-
2031	0	$-
Total	137	$139,000

Table 7-4: Substation Extreme Weather Hardening Investment Profile

Year	Count	Nominal Cost ($000)
2022	0	$-
2023	1	$700
2024	1	$4,300
2025	1	$2,700
2026	1	$3,300
2027	1	$2,900
2028	1	$4,800
2029	1	$700
2030	1	$7,200
2031	1	$900
Total	9	$33,800

Table 7-5: Distribution Overhead Feeder Hardening Investment Profile

Year	Feeder Count	Nominal Cost ($000)
2022	37	$33,300
2023	31	$29,900
2024	23	$30,000
2025	28	$30,000
2026	28	$30,000
2027	32	$30,000
2028	25	$30,000
2029	29	$30,000
2030	57	$37,000
2031	51	$37,000
Total	341	$317,200

Table 7-6: Transmission Access Enhancements Investment Profile

Year	Count	Nominal Cost ($000)
2022	25	$2,400
2023	25	$3,000
2024	4	$3,000
2025	7	$3,700
2026	4	$3,400
2027	3	$3,400
2028	3	$3,100
2029	5	$2,800
2030	5	$2,000
2031	1	$4,400
Total	82	$31,200

7.3 Program Benefits

Table 7-7 shows the restoration cost and CMI benefit for each of the programs. The ranges include the P50 to P95 values. Figure 7-3 shows each program's percentage of the total benefits compared to the program's percentage of the total capital investment. The figure shows the benefit values for both restoration cost and CMI.

Table 7-7: Program Benefit Levels

Program	Restoration Cost Percent Decrease	Storm CMI Percent Decrease
Distribution Lateral Undergrounding	~32%	~45%
Transmission Asset Upgrades	~85%	~14%
Substation Extreme Weather Hardening	20%-25%	12%-45%
Distribution Feeder Hardening	~54%	~46%
Transmission Access Enhancements	~28%	~55%

Figure 7-3: Program Benefits vs. Capital Investment

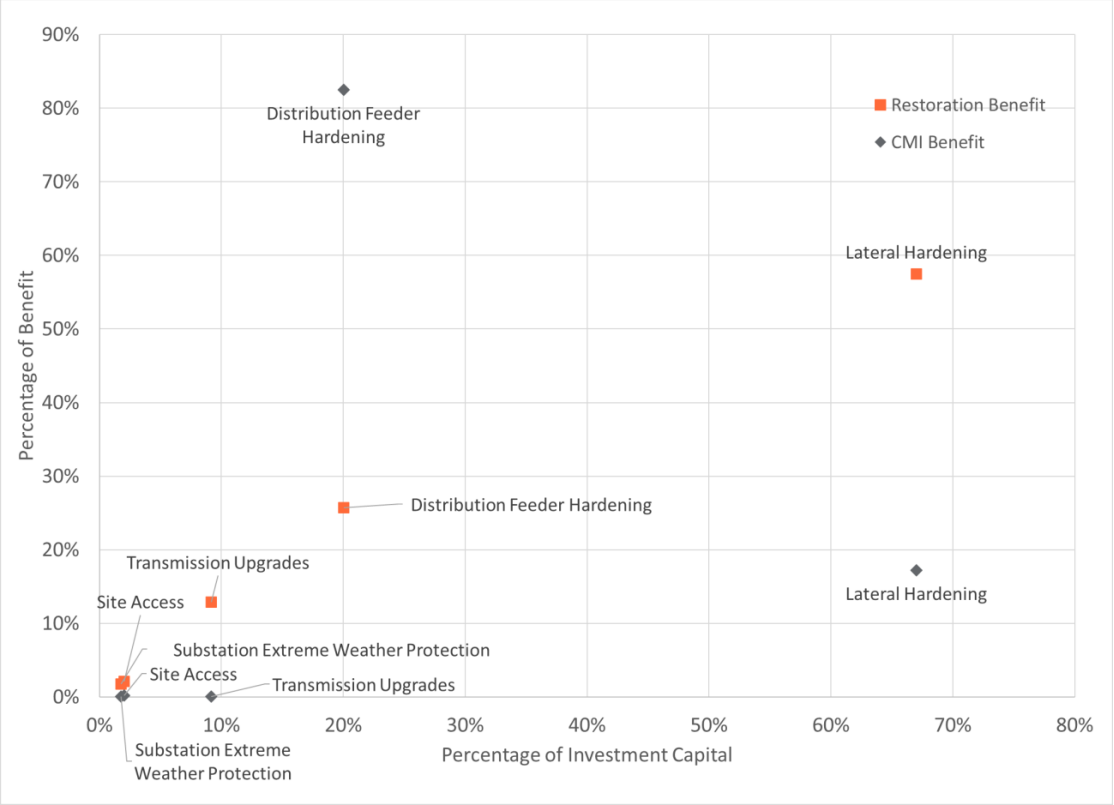


Table 7-7 and Figure 7-3 shows

- Distribution Feeder Hardening and Lateral Undergrounding account for 88 percent of the total capital investment, nearly all the CMI benefit, and approximately 81 percent of the restoration benefit.
- The Distribution Lateral Undergrounding program decreases the storm related CMI and restoration costs for the asset base by approximately 45 and 32 percent, respectively.

Additionally, the program accounts for approximately 68 percent of the total plan's invested capital, approximately 57 percent of the plan's restoration benefit, and approximately 17 percent of the plan's CMI benefit. The low overall CMI reduction relative to the total reduction is because of the high decrease from the Feeder Hardening program, specifically feeder automation.

- The Distribution Feeder Hardening program contributes approximately 82 percent of the CMI benefit of the plan, mainly from feeder automation based on the historical 'grey sky' days.
- While Transmission Assets, Substation, and Access programs achieve fairly high percentages in decreasing CMI, their total contribution to CMI reduction for the plan is low (less than 1 percent).
- Substation Hardening accounts for over 3.4 percent of the restoration benefit of the plan while only accounting for approximately 1.7 percent of the capital investment. The cost to restore flooded substations is extremely high.

7.4 Conclusions

The following include the conclusions of TEC's Storm Protection plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.59 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 6-1) shows the investment level is right before the point of diminishing returns.
- TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 33 to 35 percent. In relation to the plan's capital investment, the restoration costs savings range from 24 to 33 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 46 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.
- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.65 to $0.78 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.
- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low

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probability events and investment in the distribution system, which is impacted by all ranges of event types.

- The hardening investment will provide additional 'blue sky' benefits to customers not factored into this report.



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6. Regarding FPSC Rule 25-6.0141 Allowance for Funds Used During Construction: Please provide the Company's calculations for all bundled projects, if any, that demonstrate compliance or non-compliance with section 25-6.0141(2)2 of the above rule.

A. Not Applicable. As also explained in Response No. 41 of Citizens Second Set of Interrogatories to Tampa Electric Company. Tampa Electric does not earn or book AFUDC on any of the SPPCRC programs or projects. For projects within the SPPCRC that may last longer than one year, as soon as the capital expense is spent, those dollars go into the SPPCRC as Capital Work in Progress and beginning earning ROI and thus, are not eligible for AFUDC.

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7. Please provide all documents identified in your answers to Interrogatories 33-50.

A. Tampa Electric is providing eleven investor presentation documents that were covered each quarter starting from Quarter 2, 2019 through Quarter 4, 2021. All other documents identified in the Responses to Interrogatories 33-50 were included as part of the Response for the applicable question.

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Q2 2019 Results

August 12, 2019

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Forward-Looking Information and Non-GAAP Measures

Forward-Looking Information

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations are discussed in the Business Overview and Outlook section of Management's Discussion and Analysis ("MD&A") and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; capital market and liquidity risk; future dividend growth; timing and costs associated with certain capital projects; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; weather; commodity price risk; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; credit risk; commercial relationship risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; market energy sales prices; labour relations; and availability of labour and management resources.

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

Nothing in this document should be construed as an offer or sale of securities of Emera or any other person.

Non-GAAP Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. Refer to the Non-GAAP Financial Measures section of our MD&A for further discussion of these items.

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Business Update

Scott Balfour
President and CEO



YEAR-TO-DATE RESULTS ON TRACK

Our business is performing well and we have made significant progress on strengthening our balance sheet and reallocating capital to our strongest businesses

$1.49 YTD adjusted EPS(1)	$775 YTD Cash flow(2)
10% YTD adjusted EPS(1)(3)	1% YTD cash flow(2)(3)

(1) Adjusted EPS is a non-GAAP measure; a reconciliation to the nearest GAAP measure can be found in the appendix
(2) Operating cash flow pre-working capital in millions of dollars
(3) Compared to year-to-date ("YTD") Q2 2018

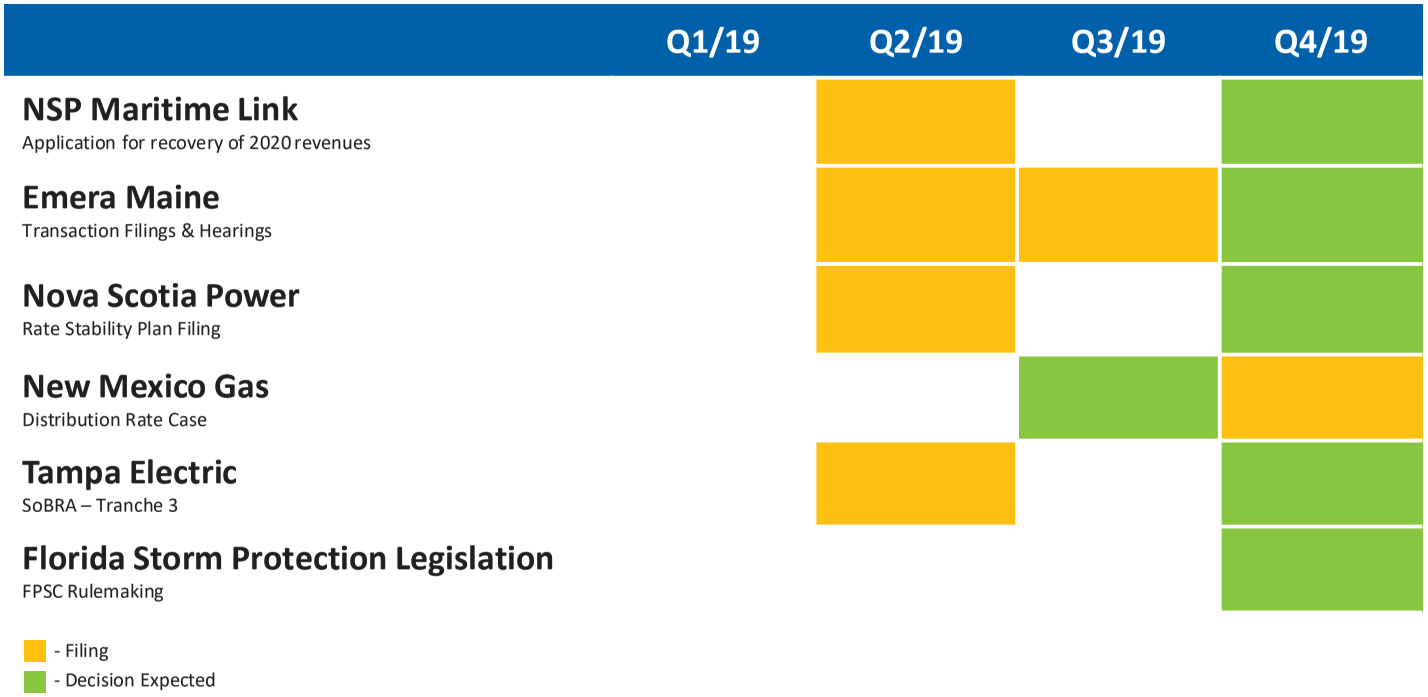
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Stable Regulatory Outlook



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Florida Investment Highlights



Solar

- Investing $850M USD to install 600MW of solar by 2021 (405MW in-service today); assessing opportunity for further investment
- Offering customers community solar through Sun Select program



Big Bend Modernization

- Investing $850M to repower Unit 1 with natural gas combined cycle technology and retire Unit 2 early
- Construction began in August 2019 and will be complete in 2023



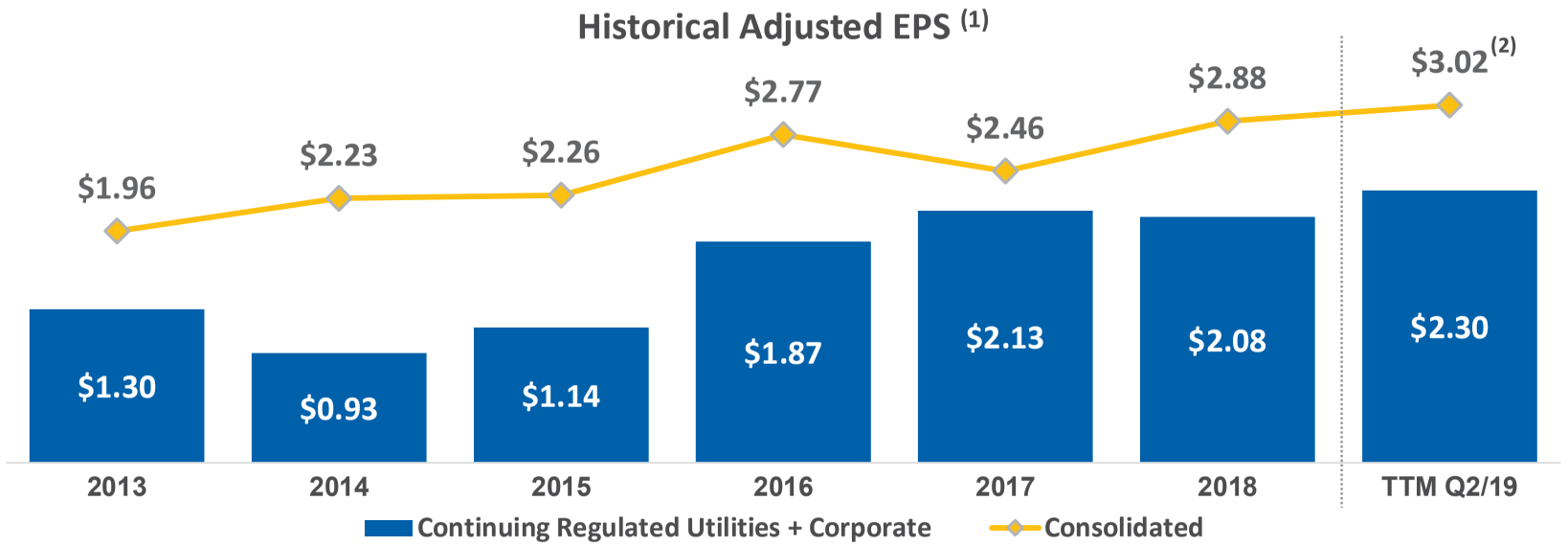
Storm Protection

- Legislation approved requiring utilities to invest in storm-protecting the grid
- FPSC rule making expected to be complete in October 2019

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Predictable, Steadily Growing Utility Earnings



Emera's continuing regulated utilities + corporate have grown by 10% over the past 5 years compared to 8% consolidated adjusted EPS growth

(1) Supporting data table, including a reconciliation between continuing regulated utilities + corporate and consolidated adjusted EPS, included on the appendix
(2) TTM does not reflect the earnings impact of asset sales; full year adjusted EPS is expected to be consistent with normalized 2018 results

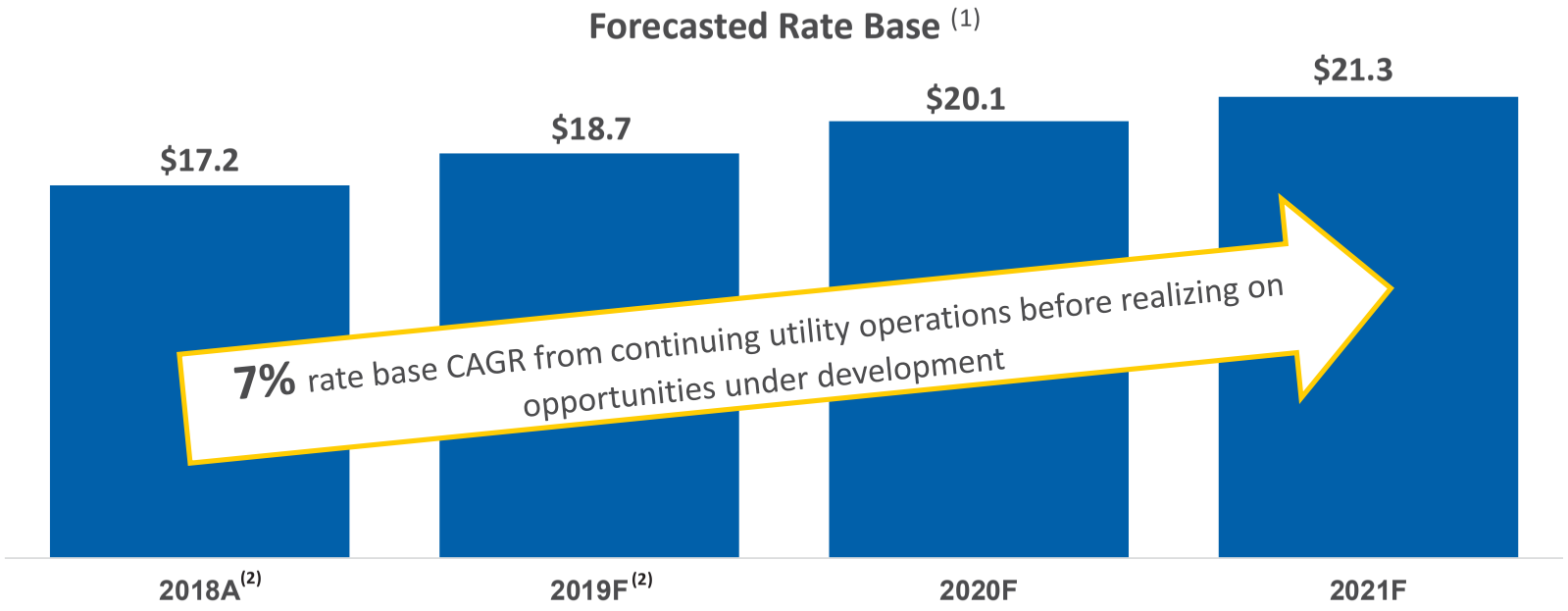
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Capital Program Drives Rate Base Growth



(1) Reflects rate base from continuing utility operations to better reflect the ongoing earnings power of the business. Average total rate base in billions of Canadian dollars. U.S. dollar denominated rate base is translated at the actual USD/CAD exchange rate of 1.30 in 2018 and a forecasted exchange rate of 1.30 in 2019-2021. Only approved and ordinary course capital projects are included. Details by affiliate can be found on slide 21 of the appendix. Forecast is subject to change in the normal course of business.

(2) Excludes Emera Maine

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Strong Performance in 2019

- ✓ **Closed NEGG and Bayside transactions and announced Emera Maine sale** for total proceeds of $2.1 billion
- ✓ **Continued to advanced strategic initiatives**, including receiving site certification and beginning construction at Big Bend and adding 280MW of new solar in Tampa
- ✓ **Established a $600 million ATM program**
- ✓ **Retired $550 million USD of holding company debt** and reduced consolidated leverage by ~200 bps
- ✓ **Solidified investment grade credit rating** with BBB rating from Fitch and a stable outlook from Moody's
- ✓ **Removed foreign ownership restrictions**, better positioning Emera to access global capital markets

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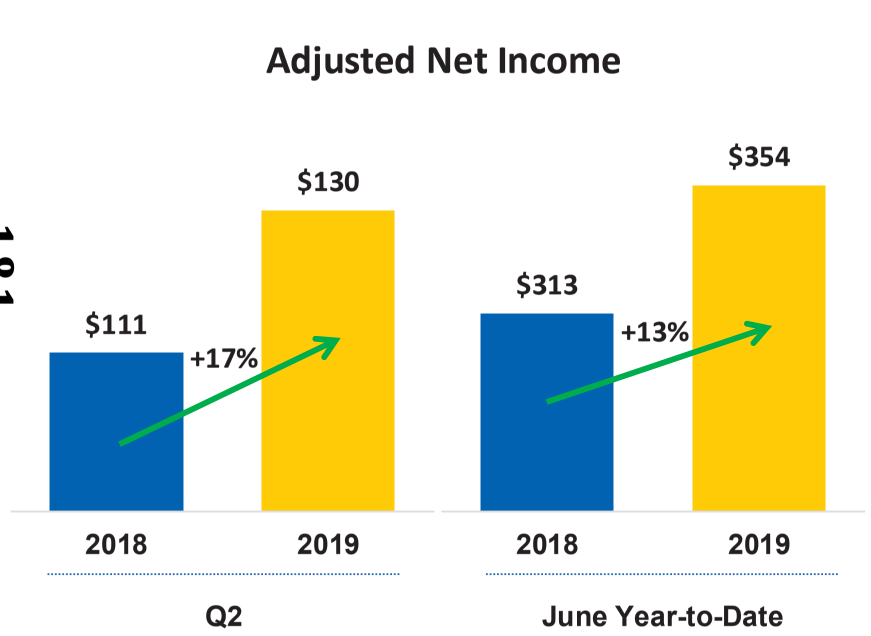
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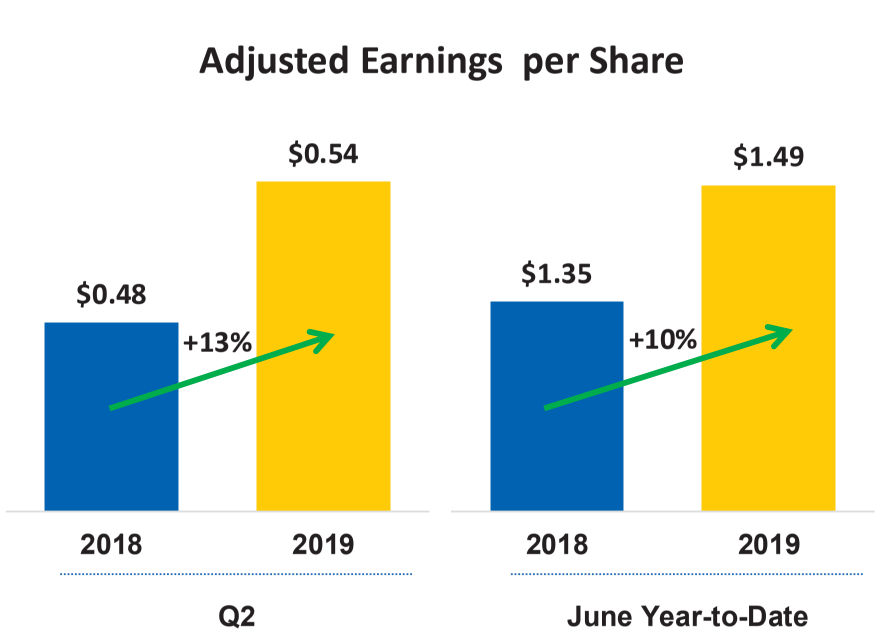
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Financial Results

Greg Blunden
CFO

Growing Adjusted Earnings and EPS





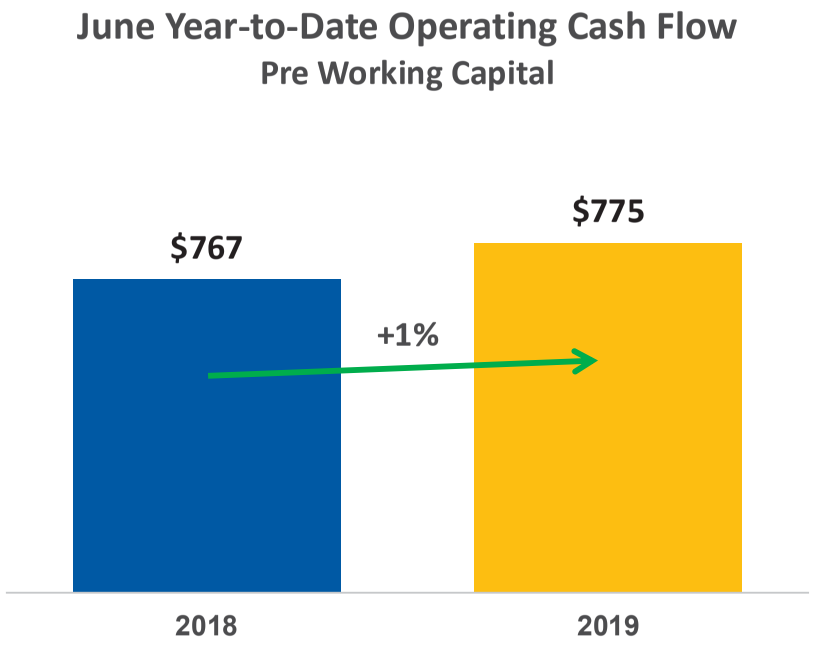
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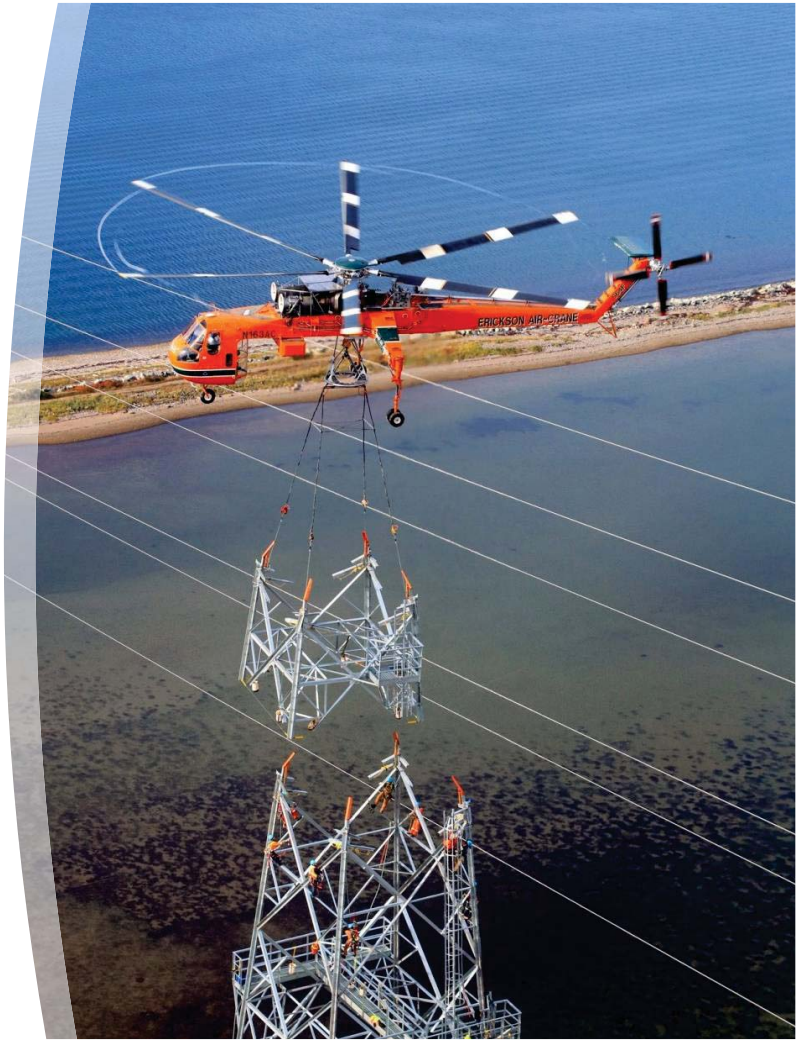
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Consistent Operating Cash Flow



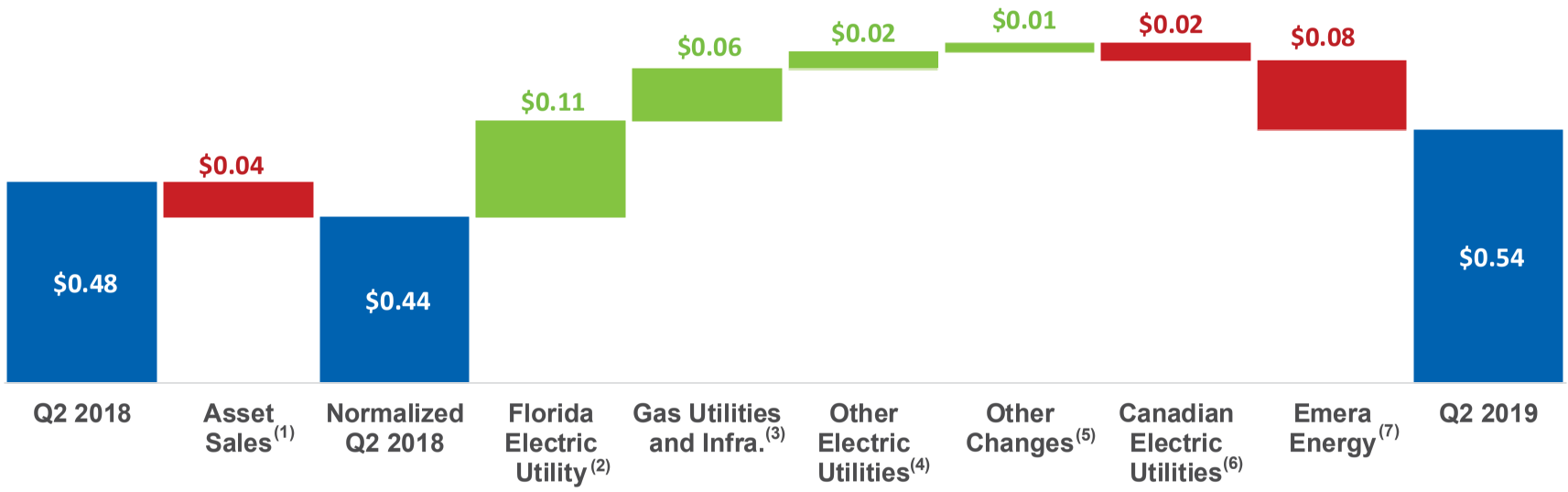


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Key Drivers of Q2 2019 Adjusted EPS



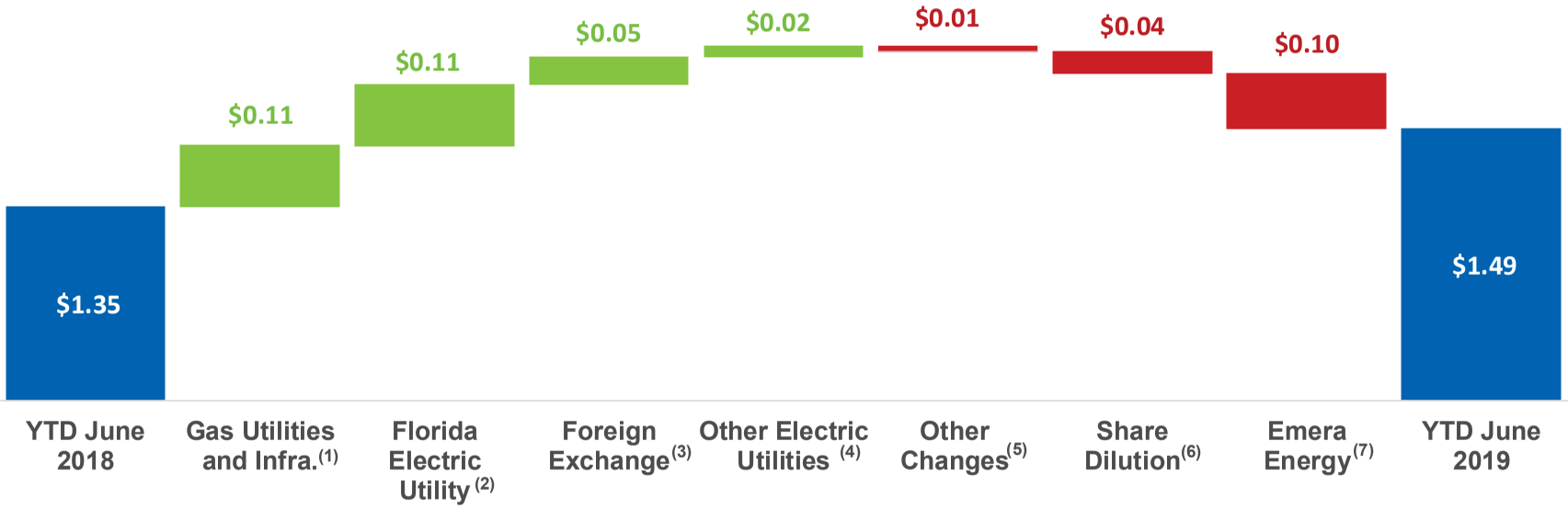
(1) Earnings impact of the sales of the NEGG portfolio and Bayside
(2) Higher base revenues related to the in-service of solar generation projects, customer growth and favourable weather, partially offset by higher interest and depreciation costs
(3) Primarily due to the $12 million adjustment recorded as a result of a favourable regulatory decision in New Mexico
(4) Higher contributions from Emera Maine due to higher capitalized construction overheads and the absence of regulatory expenses adjustments related to the 2018 distribution rate case
(5) Includes the impact of foreign exchange (+$0.02) and share dilution (-$0.01)
(6) Primarily due to lower contributions from NSPI, due to timing of regulatory deferrals and increased OM&G expenses, partially offset by increased sales volume and decreased income taxes
(7) Lower marketing and trading margins due to less market volatility

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Key Drivers of Year-to-Date Adjusted EPS



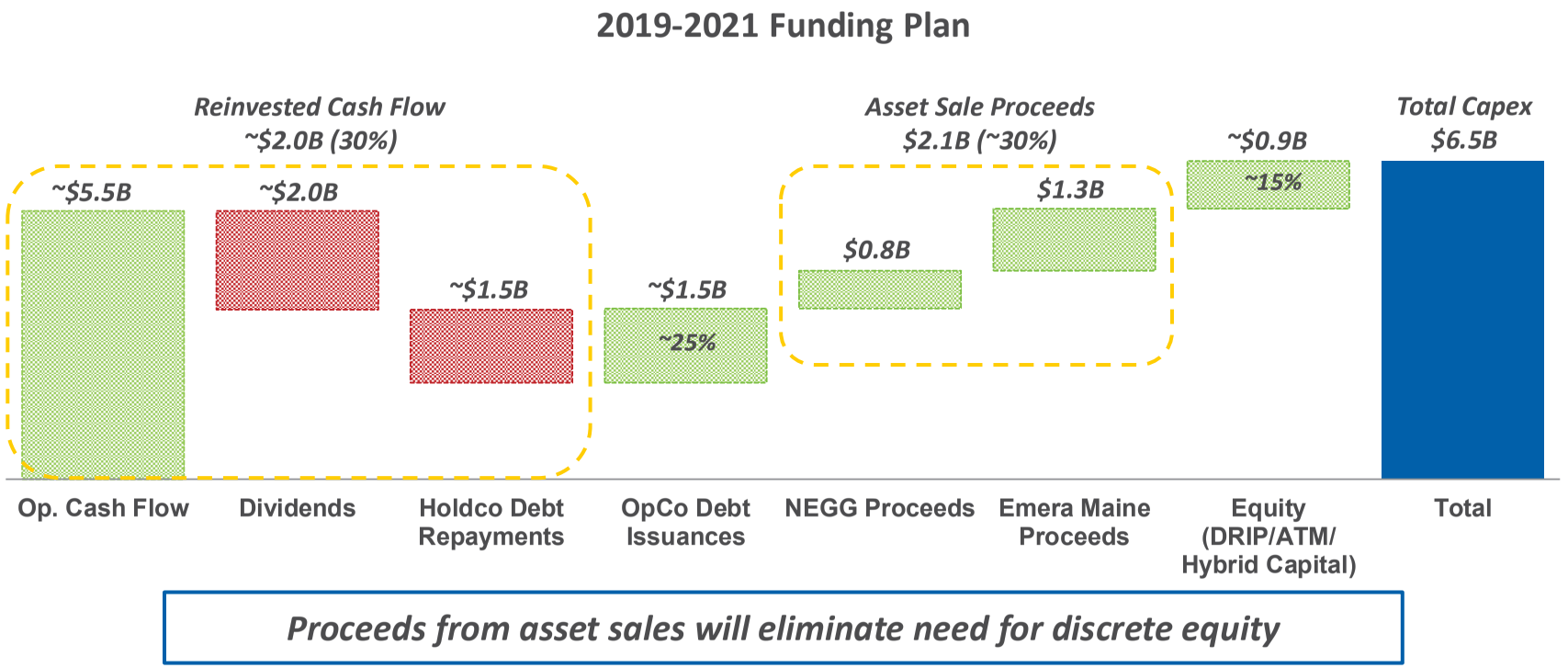
(1) Primarily due to the $12 million adjustment recorded as a result of a favourable regulatory decision in New Mexico in Q2/19 and strong Q1/19 results from PGS and NMGC
(2) Higher base revenues related to the in-service of solar generation projects and customer growth, partially offset by higher interest and depreciation costs
(3) Weaker Canadian dollar (Q2 YTD 2019 – 1.33; Q2 YTD 2018 – 1.27)
(4) Higher contributions from Emera Maine due to higher capitalized construction overheads and the absence of regulatory expenses adjustments related to the 2018 distribution rate case
(5) Consists of Canadian Electric Utilities ($0.00) and corporate (-$0.01)
(6) Reflects increase in the number of common shares issued and outstanding through normal course of business
(7) Lower marketing and trading margins due to less market volatility

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Executable Plan to Fund Rate Base Growth



Proceeds from asset sales will eliminate need for discrete equity

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Continuing to Execute on Credit Objectives

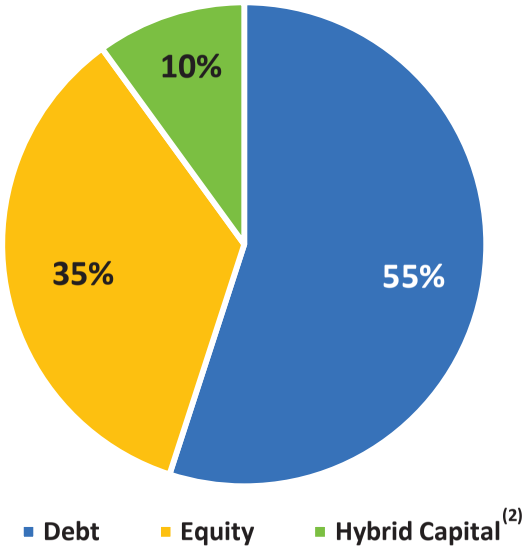
Emera Credit Objectives

1. Achieve target capital structure by 2020
2. Sustained cash flow-to-debt metrics > 12%
3. Sustained holdco debt-to-total debt < 40%

Emera Corporate Credit Ratings

Moody's	S&P	Fitch
Baa3 (Stable)	BBB[1] (Negative)	BBB (Stable)

2020 Target Capital Structure



[1] Issue rating; issuer rating of BBB+ (negative)
[2] Includes preferred shares and hybrid debt

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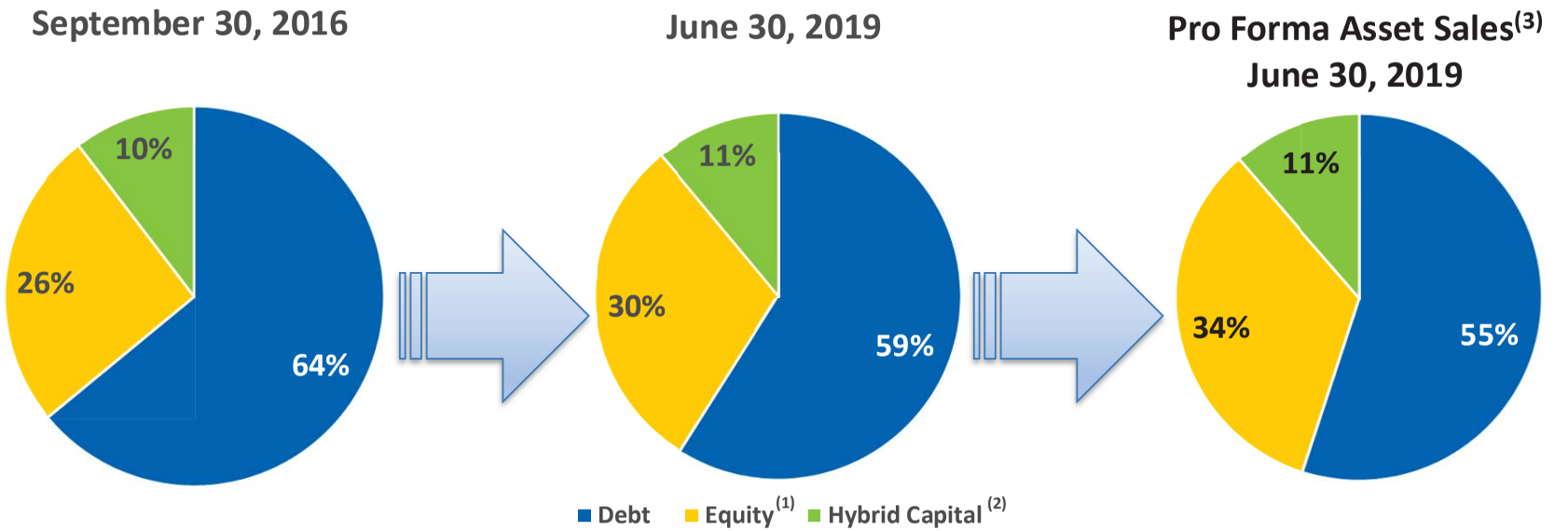
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UPCOMING EVENTS
Expected Q3/19 Results & Conference Call
Friday, November 8, 2019
Expected Q4/19 Results & Conference Call
Tuesday, February 18, 2020
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Appendix
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Strengthening the Balance Sheet



2020 Target of 55% Debt, 35% Equity and 10% Preferred Equity

(1) Equity includes the NCI and excludes AOCI
(2) Includes preferred shares and hybrid bonds
(3) Pro forma asset sales calculation shows June 30, 2019, actuals if select asset sales had been completed at that time

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Capital Forecast by Affiliate

Capital Forecast (CAD millions)[1]		2019F	2020F	2021F	Total
Tampa Electric	$	1,320	950	985	3,255
Peoples Gas		310	345	305	960
New Mexico Gas Company		100	190	135	425
Seacoast		60	65	55	180
Nova Scotia Power		360	325	345	1,030
Emera Maine		90	-	-	90
Emera Caribbean		155	70	65	290
Emera Newfoundland		40	-	190	230
Other		50	10	5	65
Subtotal – Baseline Capital Forecast	**$**	**2,485**	**1,955**	**2,085**	**6,525**
Add: Opportunities Under Development		-	190	1,130	1,320
Total Capital Forecast	**$**	**2,485**	**2,145**	**3,215**	**7,845**

[1] US dollar denominated capex is translated at a forecasted average USD/CAD exchange rate of 1.30 in 2019-2021

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Rate Base Forecast by Affiliate

Rate Base (CAD millions)[1]		2018A	2019F	2020F	2021F	2018-2021 CAGR
Tampa Electric[2]	$	8,300	9,200	9,925	10,550	8.3%
Peoples Gas[2]		1,250	1,475	1,700	1,900	15.0%
New Mexico Gas Company		725	750	850	925	8.5%
Nova Scotia Power		3,775	3,950	4,200	4,350	4.8%
Emera Caribbean		800	925	925	925	5.0%
Maritime Link		1,800	1,800	1,800	1,750	-0.9%
Labrador Island Link[3]		525	550	725	850	17.4%
Total	**$**	**17,175**	**18,650**	**20,125**	**21,520**	**7.4%**

[1] Average rate base. US dollar denominated rate base is translated at an actual average rate of 1.30 in 2018 and a forecasted average USD/CAD exchange rate of 1.30 in 2019-2021

[2] Capital structures that support the rate base include deferred tax liabilities (DTL). DTL is a zero cost-of-capital component of the capital structure in Florida. The 2018 capital structures included $1,700 million at Tampa Electric and $240 million at Peoples Gas

[3] Reflects Emera's equity investment in the project

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Historical Adjusted Earnings and EPS Contributions

millions of Canadian dollars (except per share amounts)		2013	2014	2015	2016	2017	2018	TTM Q2/19	5-Year CAGR
Adjusted net income attributable to common shareholders[1]	$	259	319	330	475	524	671	712	
Less:									
Emera Maine		(38)	(42)	(45)	(47)	(46)	(44)	(50)	
Emera Energy[2]		(38)	(98)	(119)	(24)	(24)	(120)	(96)	
Other earnings[3]		(11)	(46)	1	(84)	-	(23)	(23)	
Continuing regulated utilities + corporate	$	**172**	**133**	**167**	**320**	**454**	**484**	**543**	
Weighted average shares		133	143	146	171	213	233	236	
Continuing regulated utilities + corporate	$	**1.30**	**0.93**	**1.14**	**1.87**	**2.13**	**2.08**	**2.30**	**9.9%**
Emera Maine		0.29	0.29	0.31	0.27	0.22	0.19	0.21	
Emera Energy[2]		0.29	0.69	0.81	0.14	0.11	0.51	0.41	
Other earnings[3]		0.08	0.32	-	0.49	-	0.10	0.10	
Consolidated adjusted EPS[1]	$	**1.96**	**2.23**	**2.26**	**2.77**	**2.46**	**2.88**	**3.02**	**8.0%**

[1] Excludes the effect of mark-to-market adjustments and, for 2017, exclude the revaluation of US non-regulated deferred income taxes
[2] Excludes one-time items
[3] Includes Algonquin equity earnings (2013-2016) and one-time items recorded in Corporate and Emera Caribbean

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Emera Energy Quarterly Adjusted Earnings Contribution

Millions of Canadian dollars		Q1/18	Q2/18	Q3/18	Q4/18	Q1/19	Q2/19
Marketing and Trading	$	37	(5)	-	21	30	(20)
NEGG[(1)]		10	7	19	19	18	(2)
Maritimes Canada		4	(5)	(6)	(4)	0	(1)
Bear Swamp		4	5	6	8	4	4
Total (excl. MTM and loss on sale)	**$**	**55**	**2**	**19**	**44**	**52**	**(19)**
Net (loss)/gain on sale (recorded in Corporate)		-	-	-	-	(2)	(1)

[(1)] Q1/18 to Q1/19, inclusive, includes approximately $6 million per quarter of intercompany interest expense paid to Emera Corporate, where it was recorded as intercompany interest revenue. Emera Corporate financed the original acquisition off its balance sheet. No permanent debt financing was transferred with the sale of the gas plants.

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Emera Energy Marketing and Trading Quarterly Adjusted Earnings Contribution

Millions of US dollars		Q1	Q2	Q3	Q4	Total
2016	$	18	(9)	(1)	8	**16**
2017		10	(4)	(5)	10	**11**
2018		30	(4)	-	16	**42**
2019		22	(15)			

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Non-GAAP Reconciliation

For the millions of Canadian dollars (except per share amounts)		Three months ended June 30		Six months ended June 30	
		2019	2018	**2019**	2018
Net income (loss) attributable to common shareholders	**$**	**103**	90	**415**	361
After-tax mark-to-market gain (loss)		**(27)**	(21)	**61**	48
Adjusted net income attributable to common shareholders	**$**	**130**	111	**354**	313
Weighted average shares		**238**	232	**238**	233
Earnings per common share – basic	**$**	**0.43**	0.38	**1.75**	1.56
Adjusted earnings per common share – basic	**$**	**0.54**	0.48	**1.49**	1.35

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Emera's New Segmentation

Old	
Emera Florida and New Mexico	• Tampa Electric • Peoples Gas System • New Mexico Gas Company • Seacoast Gas (incl. in FL & NM other) • TECO Finance (incl. in FL & NM other) • New Mexico Gas Intermediate ("NMGI") (incl. in FL & NM other)
Nova Scotia Power	• Nova Scotia Power
Emera Maine	• Emera Maine
Emera Caribbean	• Emera Caribbean
Emera Energy	• Emera Energy Services • Emera Energy Generation • Bear Swamp (Equity Investment)
Corporate and Other	• Corporate • Brunswick Pipeline • M&NP (Equity Investment) • Emera Utility Services • Maritime Link (Equity Investment) • Labrador Island Link (Equity Investment)

New	
Florida Electric Utilities	• Tampa Electric
Canadian Electric Utilities	• Nova Scotia Power • Maritime Link (Equity Investment) • Labrador Island Link (Equity Investment)
Other Electric Utilities	• Emera Maine • Emera Caribbean
Gas Utilities and Infrastructure	• Peoples Gas System • New Mexico Gas Company, incl. NMGI • Seacoast Gas • Brunswick Pipeline • M&NP Pipeline (Equity Investment)
Other	• Corporate • TECO Finance • Emera Energy Services • Emera Energy Generation • Bear Swamp (Equity Investment) • Emera Utility Services

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Q3 2019 Results

November 8, 2019

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Forward Looking Information and Non-GAAP Measures

Forward-Looking Information

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations are discussed in the Business Overview and Outlook section of Management's Discussion and Analysis ("MD&A") and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; capital market and liquidity risk; future dividend growth; timing and costs associated with certain capital projects; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; weather; commodity price risk; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; credit risk; commercial relationship risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; market energy sales prices; labour relations; and availability of labour and management resources.

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

Nothing in this document should be construed as an offer or sale of securities of Emera or any other person.

Non-GAAP Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. Refer to the Non-GAAP Financial Measures section of our MD&A for further discussion of these items.

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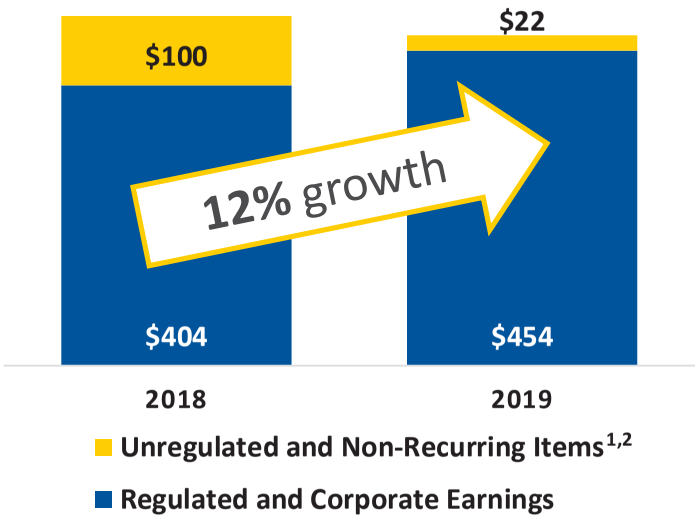
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Business Update

Scott Balfour
President and CEO

Strong Performance by Regulated Businesses

YTD Growth in Regulated Earnings



Emera Regulated Businesses	YTD Growth
Florida Electric Utility	14%
Gas Utilities and Infrastructure[3]	22%
Other Electric Utilities[4]	8%
Canadian Electric Utilities[5]	-2%
Regulated Utilities & Corporate	**12%**

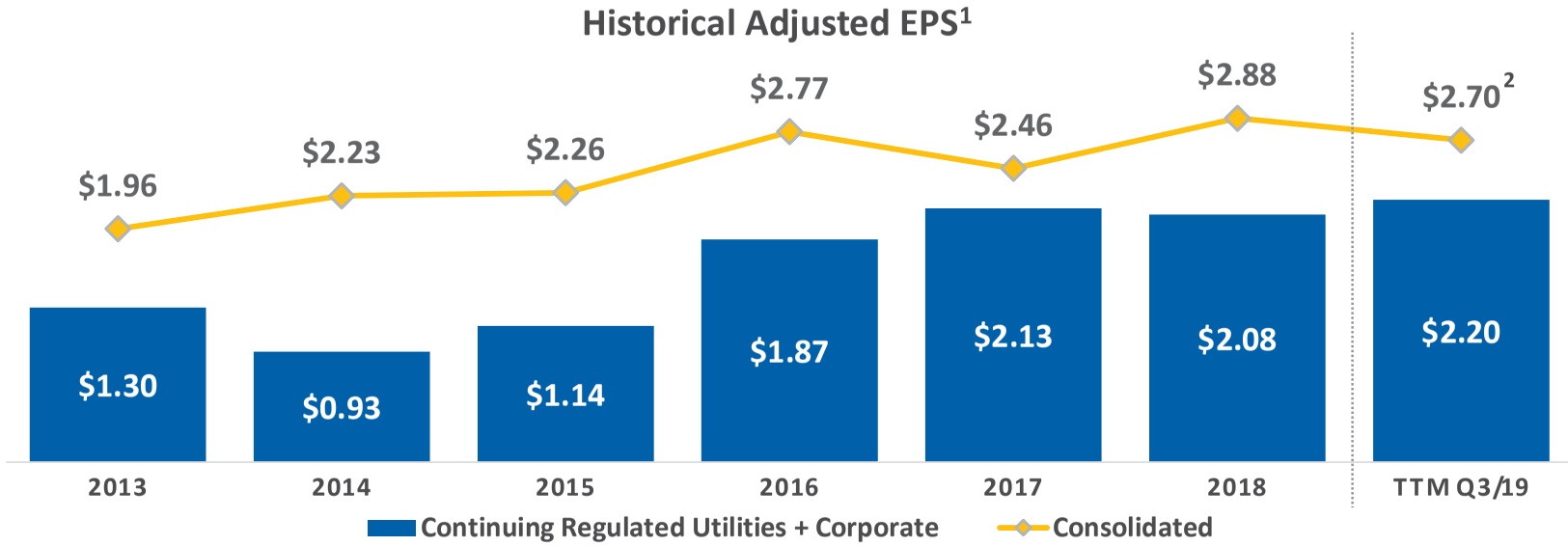
[1] 2018 includes Emera Energy earnings with gas plants and tax benefit related to change in Florida state tax apportionment factors
[2] 2019 includes Emera Energy earnings with gas plants in Q1 and NMGC regulatory adjustments, partially offset by Hurricane Dorian losses
[3] Excludes NMGC NOL and tax reform reversals
[4] Excludes Hurricane Dorian related losses in GBPC
[5] Annual growth expected in 2019; timing of regulatory deferrals causes quarterly earnings volatility while annual results are more predictable

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Steadily Growing Utility Earnings



Emera's continuing regulated utilities + corporate have grown by 10% over the past 5 years compared to 8% consolidated adjusted EPS growth

[1] Supporting data table, including a reconciliation between continuing regulated utilities + corporate and consolidated adjusted EPS, included in the appendix
[2] TTM includes earnings from the gas plants for Q4 2018 and Q1 2019

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Hurricane Dorian

Nova Scotia

- Largest storm response in NSP's history
- Power outages to 80% of customers
- 80% of affected customers reconnected within 72 hours
- No impact on NSP's Q3 earnings

Grand Bahamas

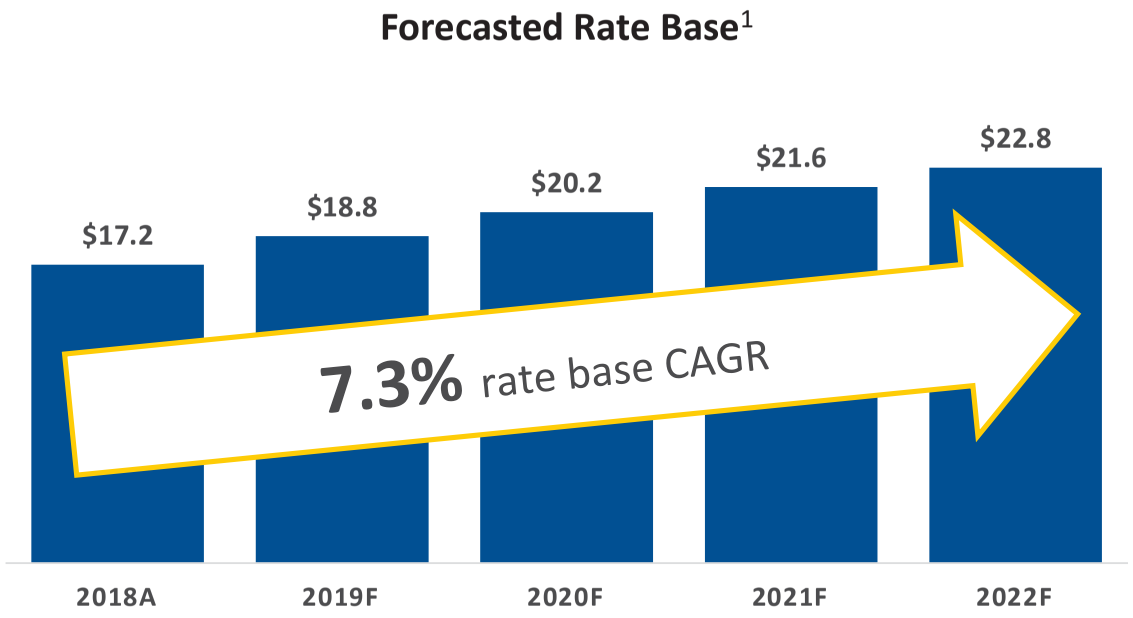
- Category 5 hurricane
- 100% of GBPC customers lost power
- All customers capable to safely receiving power now reconnected (85% of customers)
- GBPC-related earnings impact was $16 million
- Electric load ~75% of pre-storm levels

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$6.9B+ Capital Program Drives Future Rate Base Growth

2020-2022
Capital Program Highlights

- **$6.9 billion** baseline capital program
- Includes **$650 million** for storm hardening and further solar investments
- **$0.5 to $1.0 billion** of opportunities under development



[1] Excludes Emera Maine. Average total rate base in billions of Canadian dollars. U.S. dollar denominated rate base is translated at a forecasted exchange rate of 1.30 in 2019-2022. Only approved and ordinary course capital projects are included. Details by affiliate can be found in the appendix. Forecast is subject to change in the normal course of business.

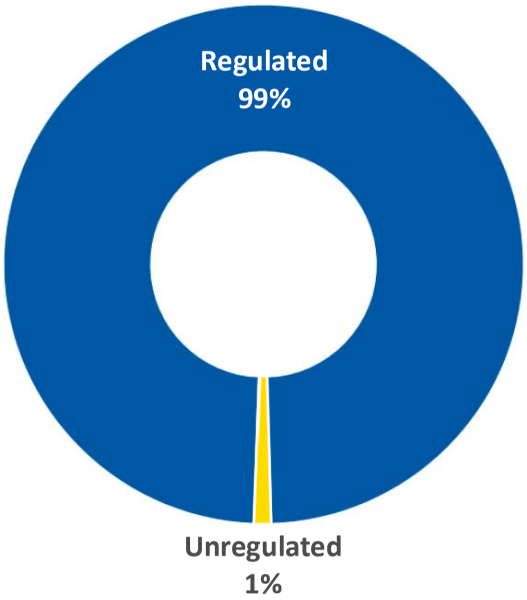
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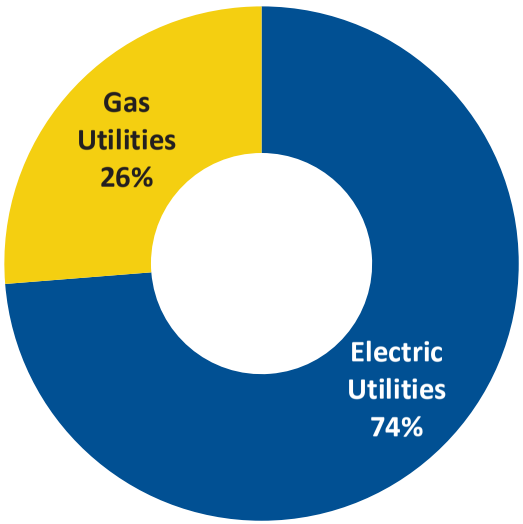
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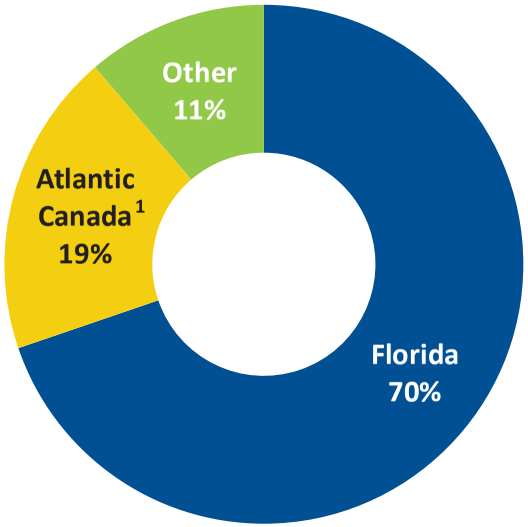
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Investing in our Regulated Utilities

2020-2022 Capital Program







[1] Atlantic Canada includes Nova Scotia Power, NSP Maritime Link and the Labrador Island Link

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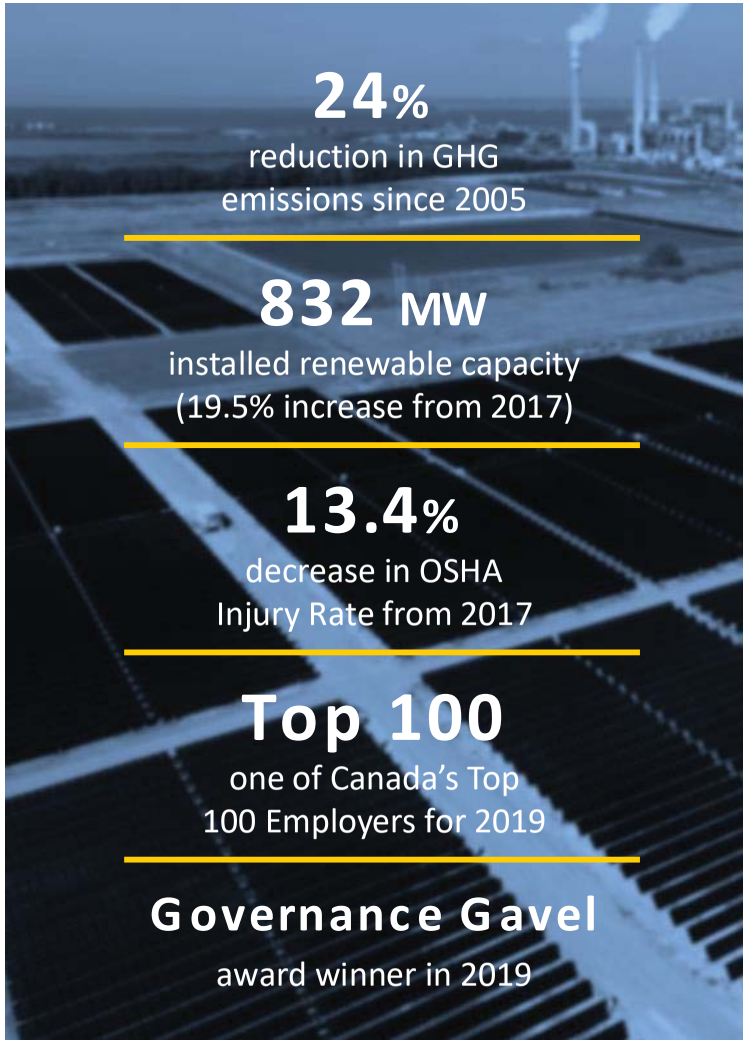
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Committed to Sustainability

- Reducing carbon emissions has been fundamental to our strategy for over a decade
- We have made significant progress transitioning to cleaner energy, especially in Nova Scotia and Florida
- Our approach to the Social and Governance aspects of our business define who we are and how we work
- Our 2018 Sustainability Update highlights Emera's progress on Environment, Social and Governance initiatives[1]



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[1] For further details refer to Emera's 2018 Sustainability Update at emerasustainability.com

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Growing our Regulated Earnings and Rate Base

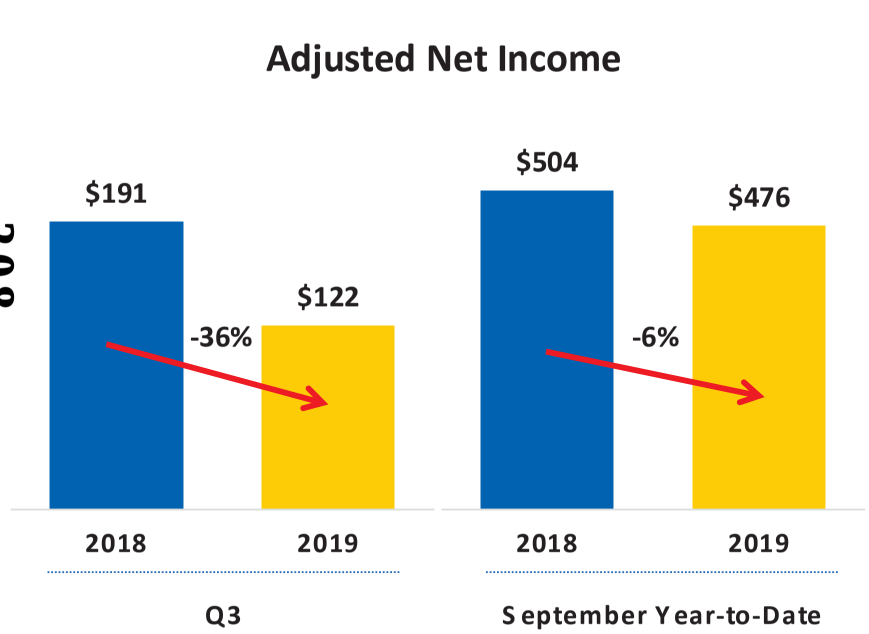
- **Regulated businesses** consistently providing significant growth
- **$6.9B+ capital program** will drive long-term rate base growth
- **$0.5-$1.0B of development opportunities** enhance and extend rate base growth
- **Rate base growth of over 7%** to support robust long-term earnings growth

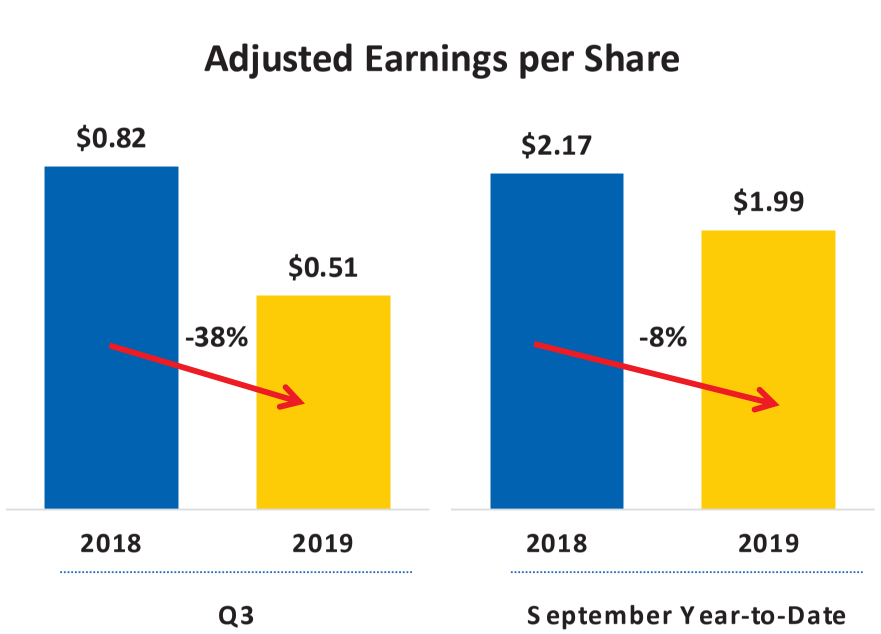
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Financial Results

Greg Blunden
CFO

Adjusted Earnings and EPS



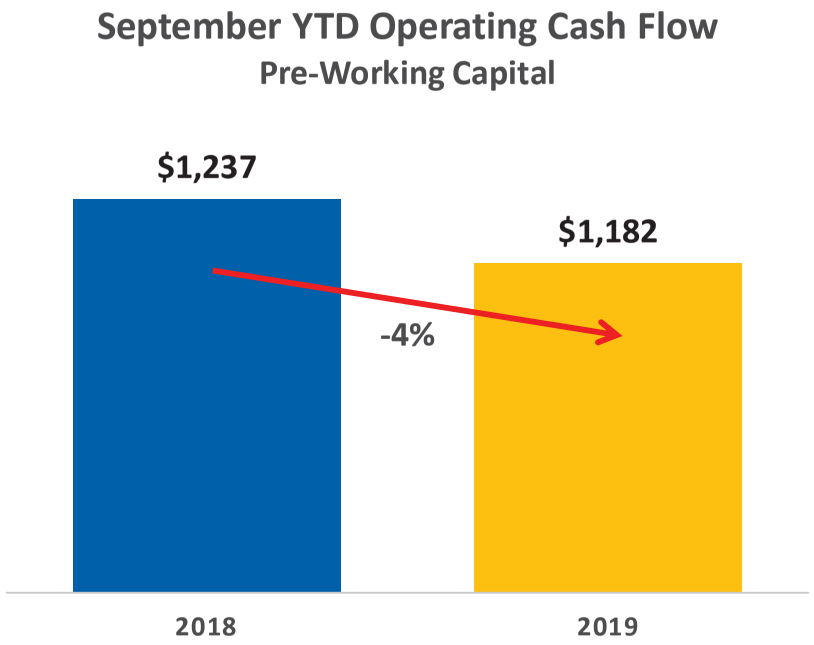


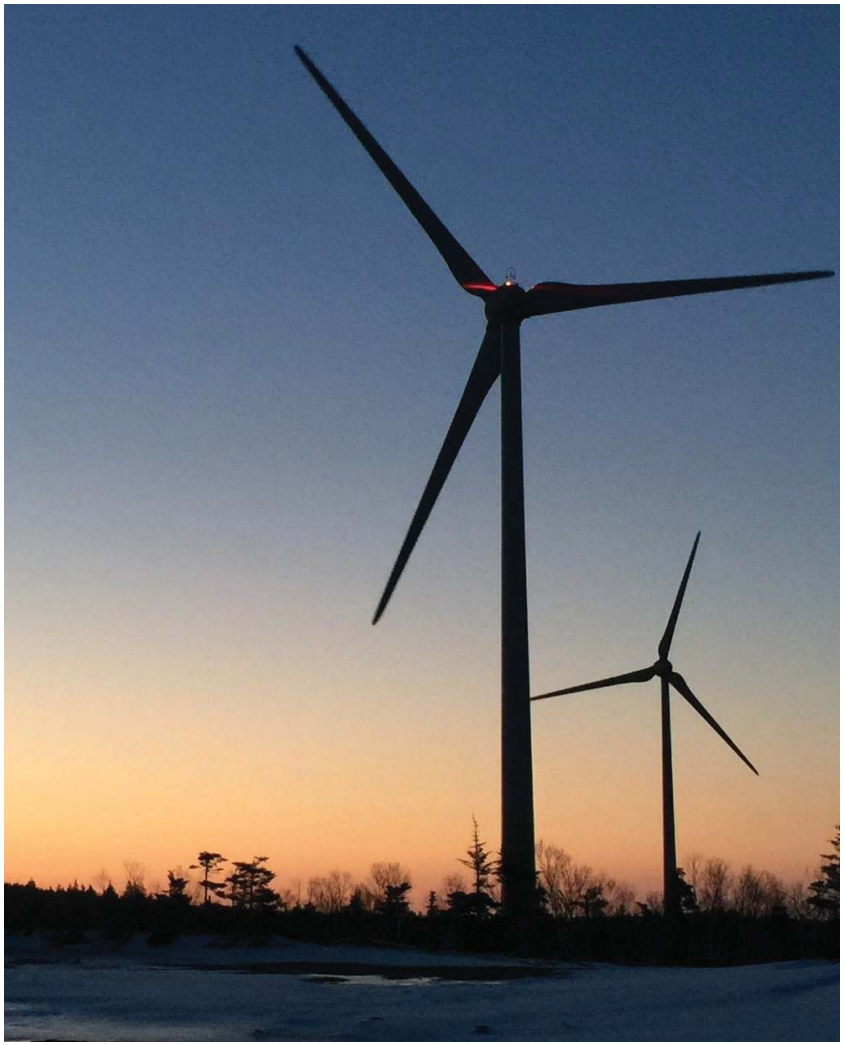
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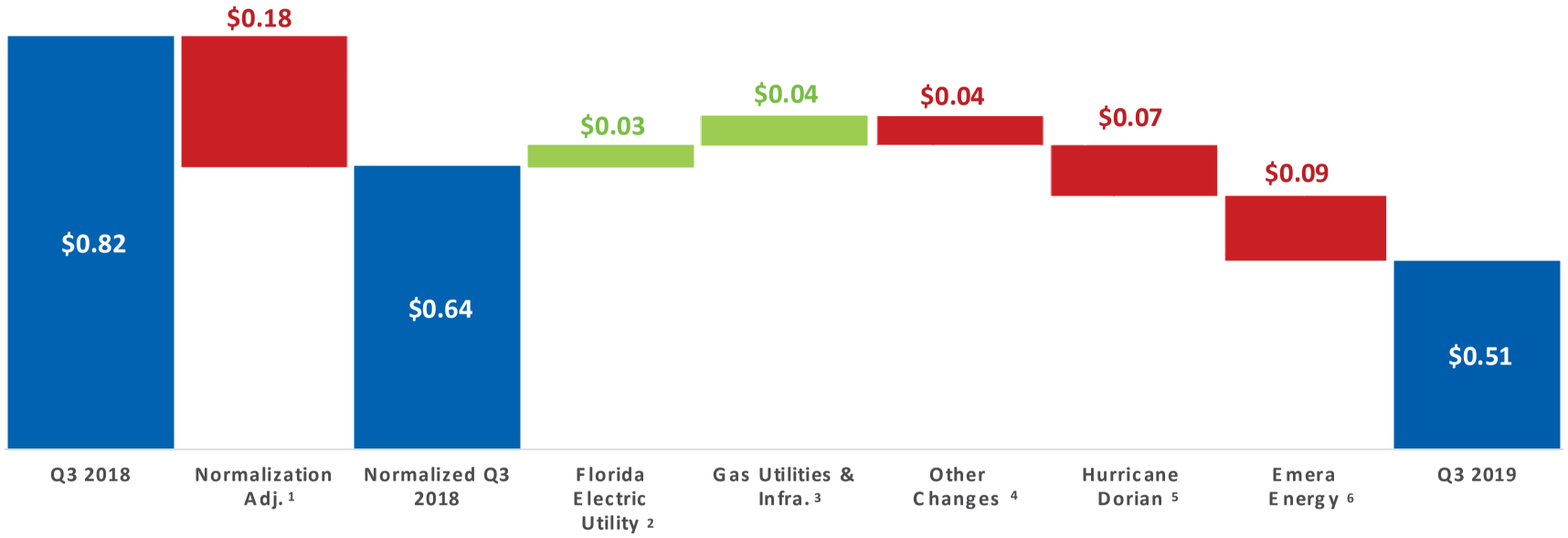
Operating Cash Flow





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Key Drivers of Q3 2019 Adjusted EPS



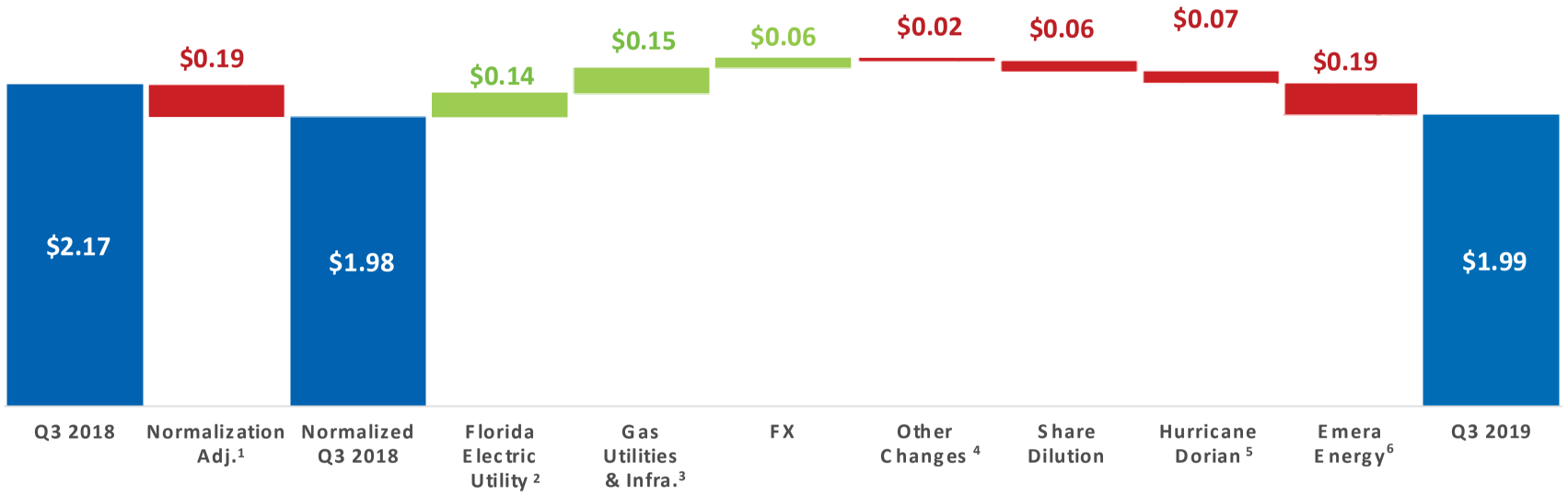
[1] 2018 benefit related to the change in Florida state tax apportionment factors and decreased earnings from Emera Energy due to sale of NEGG and Bayside
[2] Increased earnings due to increased contribution from solar, AFUDC projects, and customer growth
[3] Increased earnings due to favorable weather and regulatory adjustments in New Mexico and customer growth and lower depreciation at PGS
[4] Increased preferred stock dividends and sale transaction costs in Corporate, foreign exchange, share dilution and other immaterial variances
[5] Impacts of Hurricane Dorian in Grand Bahamas
[6] Primarily decreased earnings from marketing and trading due to unfavorable market conditions in Q3 2019

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Key Drivers of Year to Date Adjusted EPS



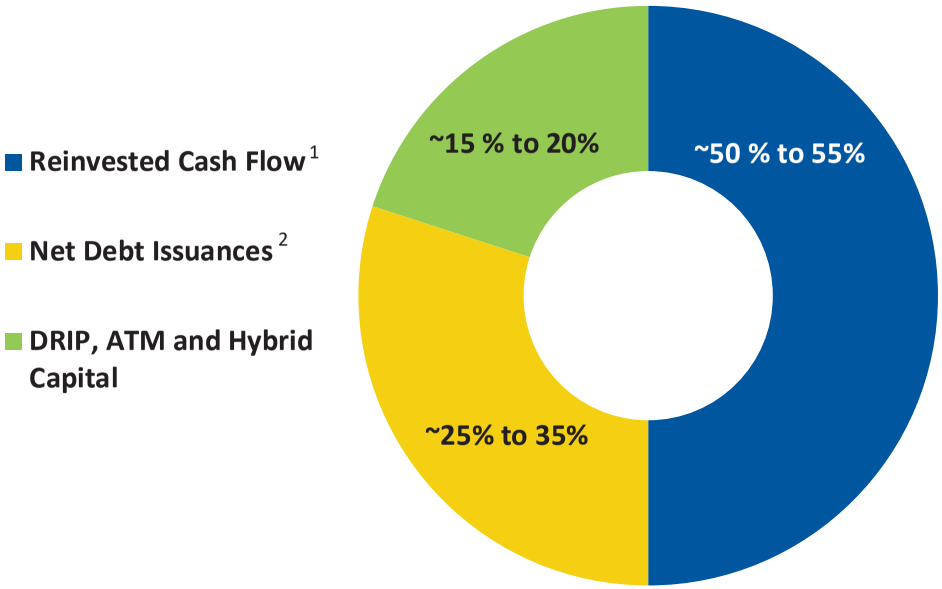
[1] 2018 benefit related to the change in Florida state tax apportionment factors and decreased earnings from Emera Energy due to sale of NEGG and Bayside
[2] Increased earnings due to increased contribution from solar, AFUDC projects, and customer growth
[3] Increased earnings due to favorable weather and regulatory adjustments in New Mexico and customer growth and lower depreciation at PGS
[4] Increased preferred stock dividends, sale transaction costs and a gain on sale of Florida property in Corporate and other immaterial variances
[5] Impacts of Hurricane Dorian in Grand Bahamas
[6] Primarily decreased earnings from marketing and trading due to unfavorable market conditions in Q2 & Q3 2019

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Target Sources of Funding 2020 to 2022



- Cash flow from operations provides significant funding
- Funding plan achieves targeted capital structure and credit metrics
- Maintains regulated capital structures through the issuance of Opco debt
- Equity requirements to be filled with DRIP and ATM, balanced with hybrid capital

[1] Reinvested cash flow is net of expected common and preferred dividend requirements
[2] Net debt issuances include Opco debt issuances net of Holdco repayments

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Executing on Credit Objectives

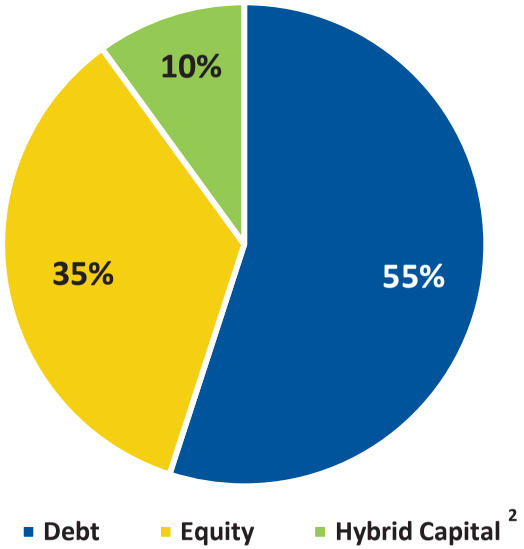
Emera Credit Objectives

1. Achieve target capital structure
2. Sustained cash flow-to-debt metrics > 12%
3. Sustained holdco debt-to-total debt < 40%

Emera Corporate Credit Ratings

Moody's	S&P	Fitch
Baa3 (Stable)	BBB[1] (Negative)	BBB (Stable)

Target Capital Structure



[1] Issue rating; issuer rating of BBB+ (negative)
[2] Includes preferred shares and hybrid debt

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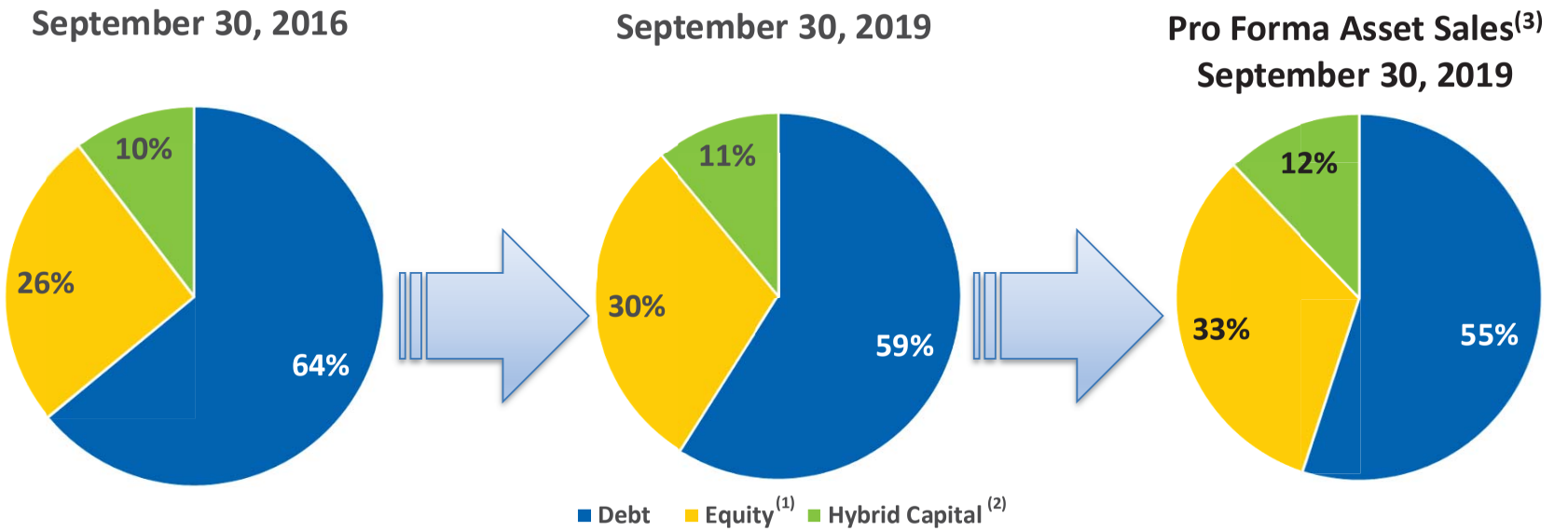
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Strengthening the Balance Sheet



Target of 55% Debt, 35% Equity and 10% Preferred Equity

(1) Equity includes the NCI and excludes AOCI
(2) Includes preferred shares and hybrid bonds
(3) Pro forma asset sales calculation shows September 30, 2019, actuals if select asset sales had been completed at that time

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Capital Forecast by Affiliate

Capital Forecast (CAD millions)[1]		2020F	2021F	2022F	Total
Tampa Electric	$	1,140	1,100	1,160	3,400
Peoples Gas		420	300	480	1,200
New Mexico Gas Company		160	120	110	390
Seacoast		80	50	80	210
Nova Scotia Power		370	380	360	1,110
Emera Caribbean		90	140	130	360
Emera Newfoundland		10	190	-	200
Other		10	10	10	30
Baseline Capital Forecast	**$**	**2,280**	**2,290**	**2,330**	**6,900**

[1] US dollar denominated capex is translated at a forecasted average USD/CAD exchange rate of 1.30 in 2020 - 2022

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Rate Base Forecast by Affiliate

Rate Base (CAD millions)[1]		2018A	2019F	2020F	2021F	2022F	2018-2022 CAGR
Tampa Electric[2]	$	8,300	9,150	9,975	10,625	11,225	7.8%
Peoples Gas[2]		1,250	1,450	1,800	2,100	2,425	18.0%
New Mexico Gas Company		725	775	825	925	950	7.0%
Nova Scotia Power		3,775	4,100	4,200	4,400	4,575	4.9%
Emera Caribbean		800	950	975	1,050	1,100	8.3%
Maritime Link		1,800	1,825	1,825	1,775	1,725	-1.1%
Labrador Island Link[3]		525	575	625	775	775	10.2%
Total	**$**	**17,175**	**18,825**	**20,225**	**21,650**	**22,775**	**7.3%**

[1] Average rate base; US dollar denominated rate base is translated at a forecasted average USD/CAD exchange rate of 1.30 in 2019-2022
[2] Capital structures that support the rate base include deferred tax liabilities (DTL), a zero cost-of-capital component of the capital structure in Florida; 2018 capital structures included DTLs of $1,700 million at Tampa Electric and $240 million at Peoples Gas
[3] Reflects Emera's equity investment in the project

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Historical Adjusted Earnings and EPS Contributions

millions of Canadian dollars (except per share amounts)		2013	2014	2015	2016	2017	2018	TTM Q3/19	5-Year CAGR
Adjusted net income attributable to common shareholders[1]	$	259	319	330	475	524	671	643	
Less:									
Emera Maine		(38)	(42)	(45)	(47)	(46)	(44)	(49)	
Emera Energy[2]		(38)	(98)	(119)	(24)	(24)	(120)	(63)	
Other earnings[3]		(11)	(46)	1	(84)	-	(23)	(7)	
Continuing regulated utilities + corporate	$	**172**	**133**	**167**	**320**	**454**	**484**	**524**	
Weighted average shares		133	143	146	171	213	233	238	
Continuing regulated utilities + corporate	$	**1.30**	**0.93**	**1.14**	**1.87**	**2.13**	**2.08**	**2.20**	**9.9%**
Emera Maine		0.29	0.29	0.31	0.27	0.22	0.19	0.21	
Emera Energy[2]		0.29	0.69	0.81	0.14	0.11	0.51	0.26	
Other earnings[3]		0.08	0.32	-	0.49	-	0.10	0.03	
Consolidated adjusted EPS[1]	$	**1.96**	**2.23**	**2.26**	**2.77**	**2.46**	**2.88**	**2.70**	**8.0%**

[1] Excludes the effect of mark-to-market adjustments and, for 2017, exclude the revaluation of US non-regulated deferred income taxes
[2] Excludes one-time items
[3] Includes Algonquin equity earnings (2013-2016) and one-time items recorded in Corporate and Emera Caribbean

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Emera Energy Quarterly Adjusted Earnings Contribution

Millions of Canadian dollars		Q1/18	Q2/18	Q3/18	Q4/18	Q1/19	Q2/19	Q3/19
Marketing and Trading	$	37	(5)	-	21	30	(20)	(19)
NEGG[1]		10	7	19	19	18	(2)	1
Maritimes Canada		4	(5)	(6)	(4)	0	(1)	-
Bear Swamp		4	5	6	8	4	4	4
Total (excl. MTM and loss on sale)	**$**	**55**	**2**	**19**	**44**	**52**	**(19)**	**(14)**
Net (loss)/gain on sale (recorded in Corporate)		-	-	-	-	(2)	(1)	-

[1] Q1/18 to Q1/19, inclusive, includes approximately $6 million per quarter of intercompany interest expense paid to Emera Corporate, where it was recorded as intercompany interest revenue. Emera Corporate financed the original acquisition off its balance sheet. No permanent debt financing was transferred with the sale of the gas plants.

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Emera Energy Marketing and Trading Quarterly Adjusted Earnings Contribution

Millions of US dollars		Q1	Q2	Q3	Q4	Total
2016	$	18	(9)	(1)	8	**16**
2017		10	(4)	(5)	10	**11**
2018		30	(4)	-	16	**42**
2019		22	(15)	(14)		

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Non-GAAP Reconciliation

For the millions of Canadian dollars (except per share amounts)		Three months ended September 30		Nine months ended September 30	
		2019	2018	**2019**	2018
Net income (loss) attributable to common shareholders	$	**55**	118	**470**	479
After-tax mark-to-market gain (loss)		**(67)**	(73)	**(6)**	(25)
Adjusted net income attributable to common shareholders	$	**122**	191	**476**	504
Weighted average shares		**241**	234	**239**	232
Earnings per common share – basic	$	**0.23**	0.51	**1.97**	2.06
Adjusted earnings per common share – basic	$	**0.51**	0.82	**1.99**	2.17

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Emera's New Segmentation

Old	
Emera Florida and New Mexico	• Tampa Electric • Peoples Gas System • New Mexico Gas Company • Seacoast Gas (incl. in FL & NM other) • TECO Finance (incl. in FL & NM other) • New Mexico Gas Intermediate ("NMGI") (incl. in FL & NM other)
Nova Scotia Power	• Nova Scotia Power
Emera Maine	• Emera Maine
Emera Caribbean	• Emera Caribbean
Emera Energy	• Emera Energy Services • Emera Energy Generation • Bear Swamp (Equity Investment)
Corporate and Other	• Corporate • Brunswick Pipeline • M&NP (Equity Investment) • Emera Utility Services • Maritime Link (Equity Investment) • Labrador Island Link (Equity Investment)

New	
Florida Electric Utilities	• Tampa Electric
Canadian Electric Utilities	• Nova Scotia Power • Maritime Link (Equity Investment) • Labrador Island Link (Equity Investment)
Other Electric Utilities	• Emera Maine • Emera Caribbean
Gas Utilities and Infrastructure	• Peoples Gas System • New Mexico Gas Company, incl. NMGI • Seacoast Gas • Brunswick Pipeline • M&NP Pipeline (Equity Investment)
Other	• Corporate • TECO Finance • Emera Energy Services • Emera Energy Generation • Bear Swamp (Equity Investment) • Emera Utility Services

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Emera Segment Reconciliation

Old Segments	New Segments	Actual Q1/19	Actual Q2/19	Actual Q3/19	Actual Q1/18	Actual Q2/18	Actual Q3/18	Actual Q4/18
Emera Florida & New Mexico		**114**	**143**	**153**	**90**	**97**	**140**	**101**
Tampa Electric	Florida Electric Utility	61	125	153	60	95	143	83
Peoples Gas	Gas Utilities and Infrastructure	24	18	14	19	15	12	16
NMGC	Gas Utilities and Infrastructure	31	10	(1)	22	(3)	(7)	13
Seacoast	Gas Utilities and Infrastructure	2	2	2	2	2	2	2
TECO Corporate	Other	(4)	(12)	(15)	(13)	(12)	(10)	(13)
Nova Scotia Power Inc.	Canadian Utilities	**71**	**19**	**13**	**65**	**23**	**15**	**28**
Emera Maine	Other Utilities	**10**	**12**	**15**	**10**	**6**	**17**	**11**
Emera Caribbean	Other Utilities	**6**	**11**	**8**	**5**	**12**	**14**	**14**
Emera Energy	Other	**52**	**(19)**	**(14)**	**55**	**2**	**19**	**44**
Corporate & Other		**(29)**	**(36)**	**(53)**	**(23)**	**(29)**	**(14)**	**(31)**
ENL (NSPML and LIL)	Canadian Utilities	25	23	20	25	25	21	16
Pipelines	Gas Utilities and Infrastructure	10	10	10	10	11	8	12
Corporate	Other	(63)	(69)	(84)	(58)	(66)	(43)	(53)
Emera Utility Services	Other	(1)	-	1	-	1	-	(6)
Total		**224**	**130**	**122**	**202**	**111**	**191**	**167**
WA Shares		236	239	241	231	233	234	235
Adj. EPS		**0.95**	**0.54**	**0.51**	**0.87**	**0.48**	**0.82**	**0.71**

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Fourth Quarter 2019

February 18, 2020

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Forward Looking Information and Non-GAAP Measures

Forward-Looking Information

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations are discussed in the Business Overview and Outlook section of Management's Discussion and Analysis ("MD&A") and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; capital market and liquidity risk; future dividend growth; timing and costs associated with certain capital projects; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; weather; commodity price risk; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; credit risk; commercial relationship risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; market energy sales prices; labour relations; and availability of labour and management resources.

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

Nothing in this document should be construed as an offer or sale of securities of Emera or any other person.

Non-GAAP Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. Refer to the Non-GAAP Financial Measures section of our MD&A for further discussion of these items.

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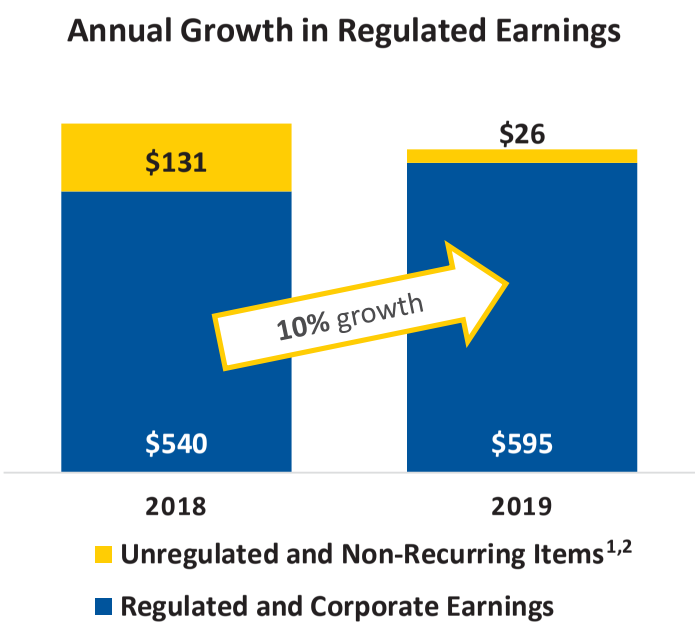
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Business Update

Scott Balfour
President and CEO

Strong Performance by Regulated Businesses



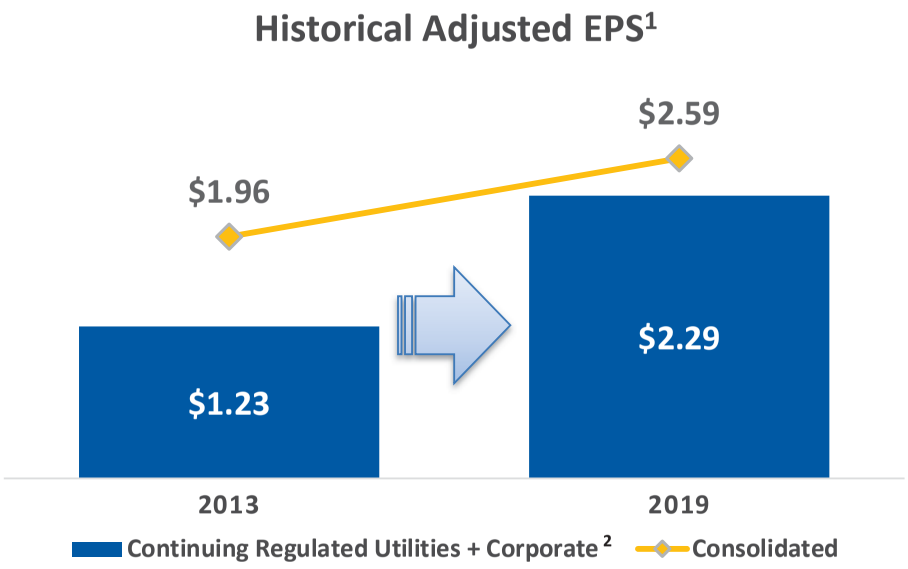
Emera Regulated Businesses	Annual % Growth
Florida Electric Utility	10%
Canadian Electric Utilities	5%
Other Electric Utilities[3]	0%
Gas Utilities and Infrastructure[4]	14%
Regulated Utilities & Corporate	**10%**

Emera's earnings quality continues to improve as regulated earnings grow

[1] 2018 includes Emera Energy earnings with gas plants and tax benefit related to change in Florida state tax apportionment factors
[2] 2019 includes Emera Energy earnings with gas plants in Q1 and NMGC regulatory adjustments, partially offset by Hurricane Dorian losses
[3] Excludes Hurricane Dorian related losses in GBPC
[4] Excludes NMGC regulatory adjustments ($19 million in 2019 and $8 million in 2018)

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Steadily Growing Utility Earnings



Emera's consolidated adjusted EPS has grown 5% in the past 6 years, whereas the continuing regulated utilities + corporate has grown by 11%

[1] Supporting data table, including a reconciliation between continuing regulated utilities + corporate and consolidated adjusted EPS, included in the appendix for 2013 to 2019
[2] Continuing regulated utilities + corporate includes Emera consolidated adjusted EPS less Emera Energy Services and Generation, Emera Maine, and one-time items in the Other segment

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Hurricane Dorian Update

Grand Bahamas

- Currently ~17,800 customers have been reconnected, compared to ~19,300 prior to the hurricane
- Load continues to improve as the island continues to recover
- Exploring longer-term distributed renewable energy solutions
- Agreement has been reached related to the recovery of storm related costs (5 years)
- Partial insurance payment of $15 million USD has been received after year-end



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Emera Maine Update

MPUC

- Settlement agreement with Office of the Public Advocate and intervenors filed with the MPUC on December 9, 2019
- Hearing on February 6, 2020 reviewed additional evidence and cross examined experts
- Expect deliberation on the settlement agreement in late February or early March 2020
- Transaction will close within 3 days of receiving MPUC approval

FERC

- Approved June 25, 2019

Hart-Scott-Rodino

- Conditions satisfied July 24, 2019

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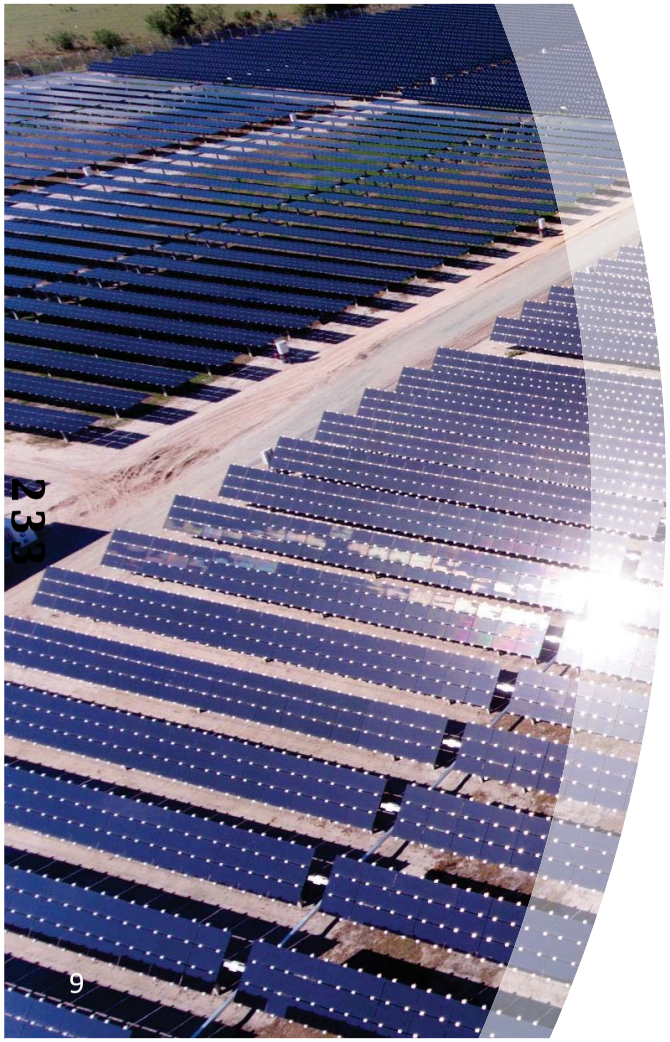
Investor Day

February 24 – 25th

- ~55% of Emera's rate base is located in Florida
- Networking with the Emera management team
- Site tours will showcase Emera's decarbonization strategy in Tampa Electric
  - Big Bend Modernization project
  - Solar/Energy Storage
- Presentations from the leaders of select affiliates
  - Webcast is available



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Looking Back on 2019

- **Regulated businesses** provided significant growth
- **Funding program** progress
  - **Repaid holdco debt** with proceeds from the **sale of the gas plants**
  - Established an **ATM program**
  - Sale of **Emera Maine** well advanced
- **$6.9B capital program**, with an incremental $0.5 to $1.0B of development opportunities (2020 to 2022)
- Forecasted **rate base growth of +7%** to support robust long-term earnings growth
- Successfully executing on **strategic initiatives** with 554 MW of solar placed in-service and work on Big Bend Modernization project underway

Emera

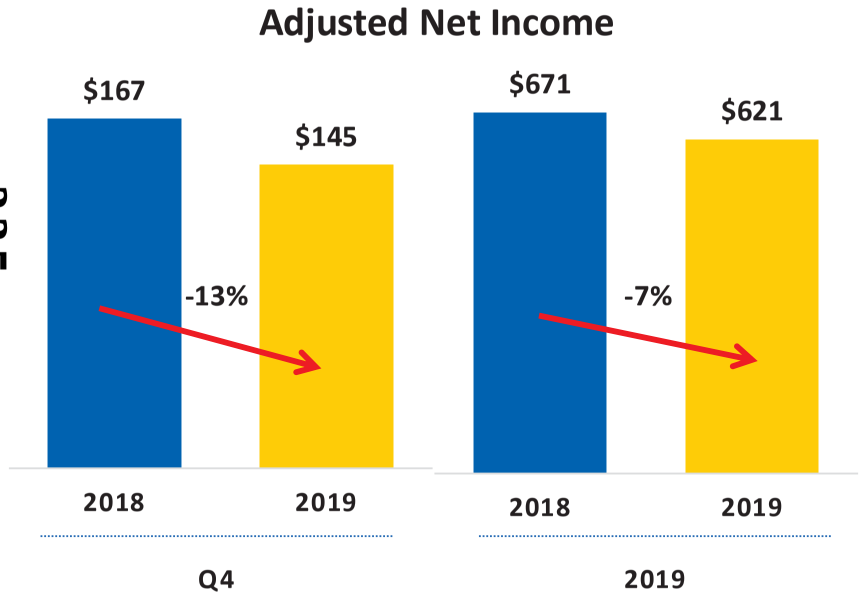
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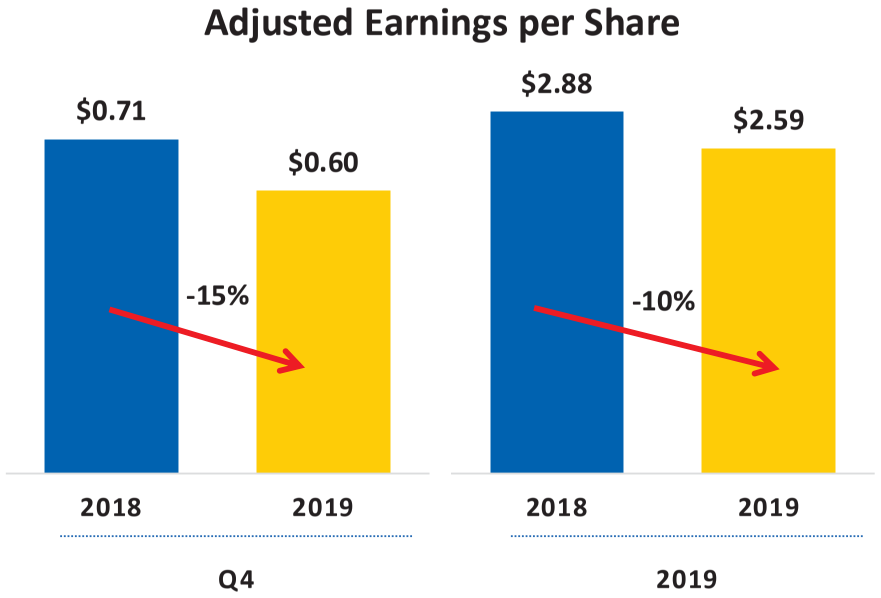
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Financial Results

Greg Blunden
CFO

Adjusted Earnings and Adjusted EPS



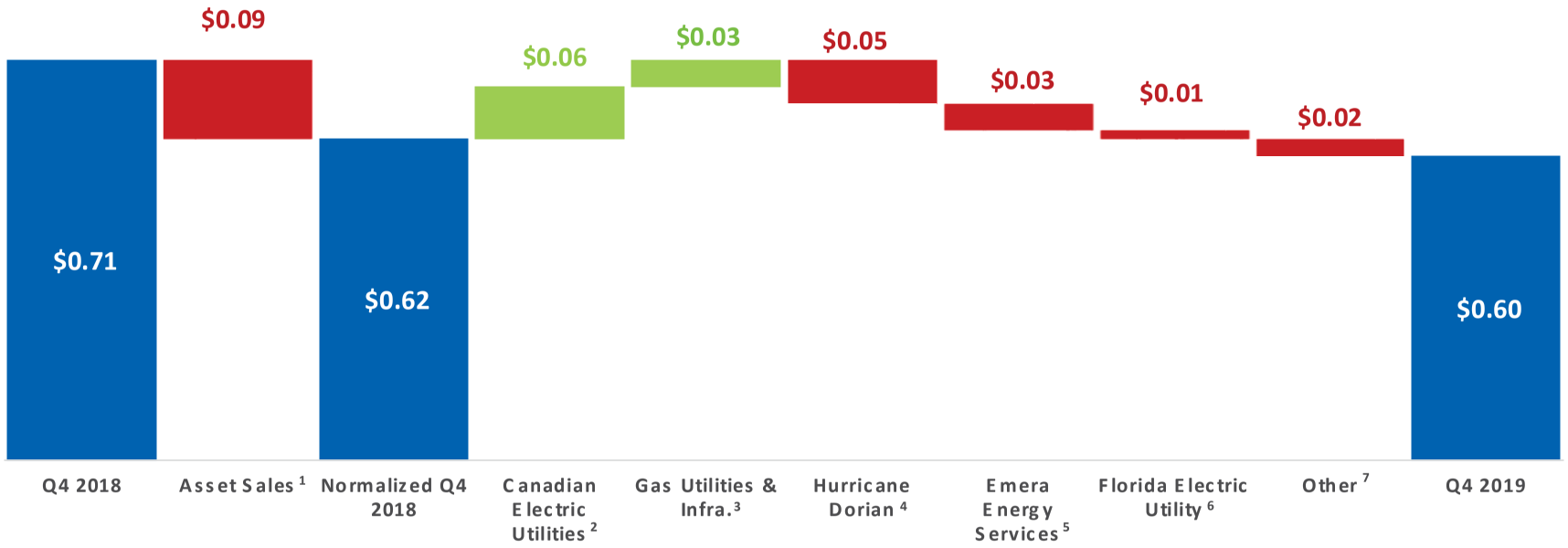


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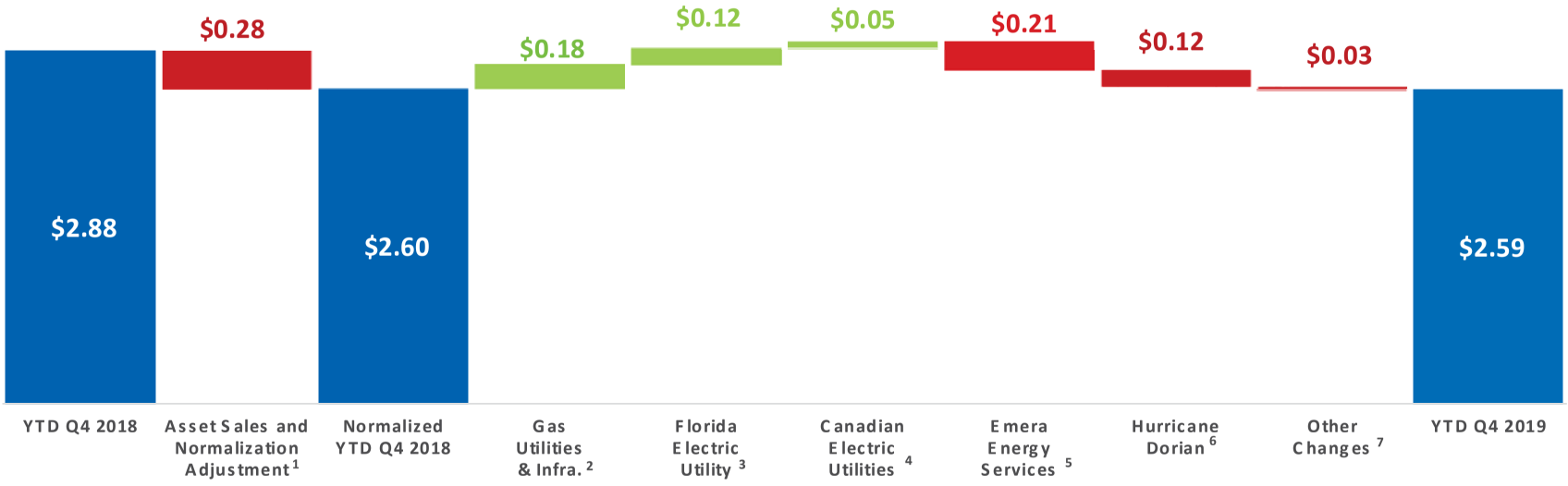
Key Drivers of Q4 2019 Adjusted EPS



[1] Decreased earnings from Emera Energy due to sale of NEGG and Bayside
[2] Increased earnings from higher income from equity investments, timing of deferrals, higher non-fuel revenues, lower non-current service pension costs and decreased income taxes
[3] Increased earnings due to favorable weather and regulatory adjustments in New Mexico and customer growth and lower depreciation at PGS
[4] Impacts of Hurricane Dorian in Grand Bahamas
[5] Decreased earnings from marketing and trading due to unfavorable market conditions
[6] Decreased earnings due to unfavourable weather compared to Q4 2018
[7] Increased sale transaction costs in Corporate, foreign exchange, share dilution and other immaterial variances

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Key Drivers of Year to Date Adjusted EPS



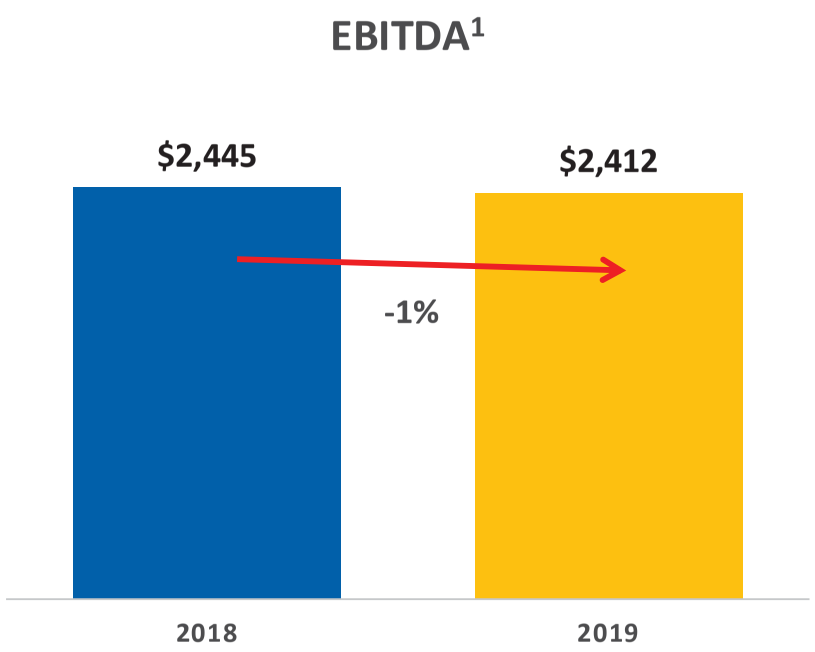
[1] 2018 benefit related to the change in Florida state tax apportionment factors and decreased earnings from Emera Energy Generation due to sale of NEGG and Bayside
[2] Increased earnings due to favorable weather and regulatory adjustments in New Mexico and customer growth and lower depreciation at PGS
[3] Increased earnings due to increased contribution from solar, AFUDC projects, and customer growth
[4] Increased earnings from higher income from equity investments, higher non-fuel revenues, lower non-current service pension costs and decreased income taxes
[5] Decreased earnings from marketing and trading due to unfavorable market conditions
[6] Impacts of Hurricane Dorian in Grand Bahamas
[7] Reflects increase in the number of common shares issued and outstanding (-$0.08), increased earnings from the weakening of the CAD in 2019 compared to 2018 (+$0.06), and sale transaction costs and a gain on sale of Florida property in Corporate and other immaterial variances (-$0.01)

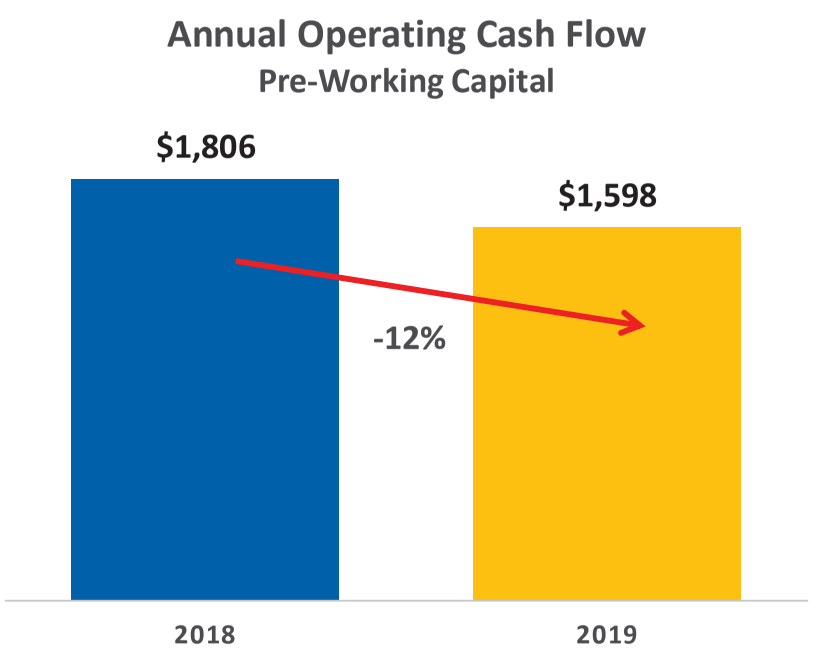
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EBITDA and Operating Cash Flow





[1] Refer to the 2019 Emera financial statements and MD&A for a reconciliation of EBITDA to reported net income

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Upcoming Investor Events

Emera 2020 Investor Day
Tuesday, February 25
Tampa, Florida

Expected Q1 2020 Results & Conference Call
Wednesday, May 13

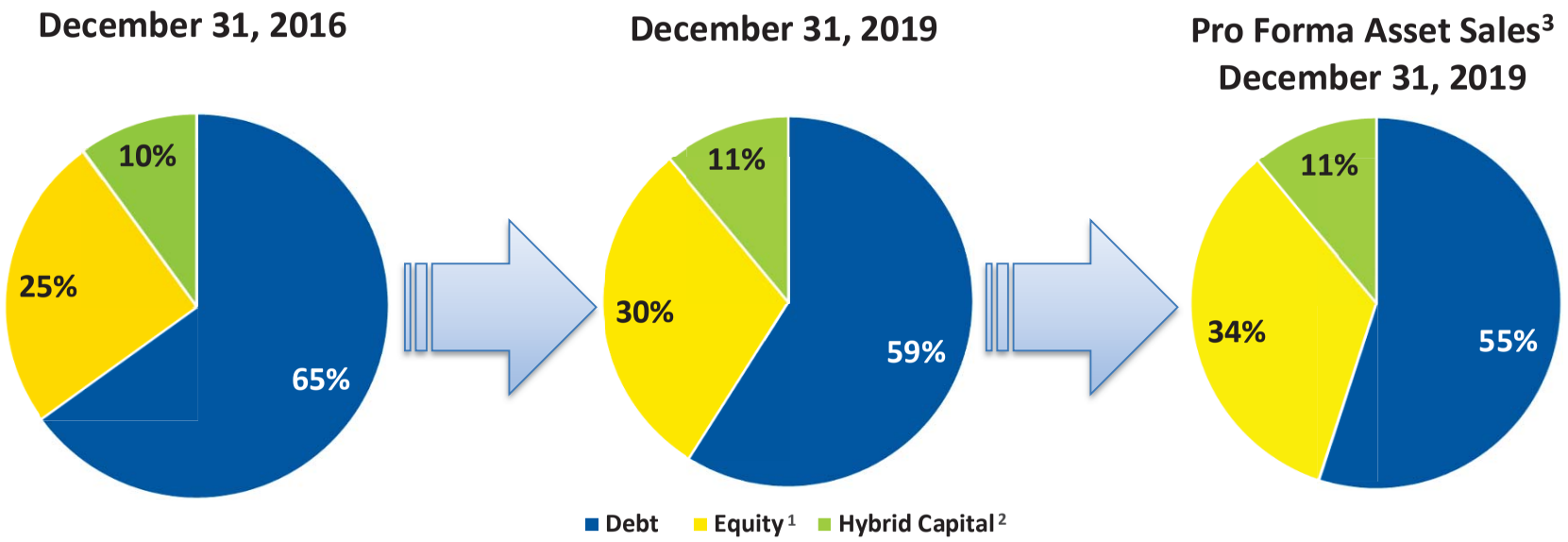
Annual General Meeting
Thursday, May 14, 2020
Toronto, Ontario

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Strengthening the Balance Sheet



Target of 55% Debt, 35% Equity and 10% Preferred Equity

[1] Equity includes the NCI and excludes AOCI
[2] Includes preferred shares and hybrid bonds
[3] Pro forma asset sales calculation shows December 31, 2019, actuals if select asset sales had been completed at that time

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Historical Adjusted Earnings and EPS Contributions

millions of Canadian dollars (except per share amounts)		2013	2014	2015	2016	2017	2018	2019	6-Year CAGR
Adjusted net income attributable to common shareholders[1]	$	259	319	330	475	524	671	621	
Less:									
Emera Maine		(38)	(42)	(45)	(47)	(46)	(44)	(46)	
Emera Energy[2]		(45)	(98)	(130)	(24)	(24)	(120)	(37)	
Other earnings[3]		(13)	(46)	-	(84)	-	(23)	10	
Continuing regulated utilities + corporate	$	**163**	**133**	**155**	**320**	**454**	**484**	**548**	
Weighted average shares		133	143	146	171	213	233	240	
Continuing regulated utilities + corporate	$	**1.23**	**0.93**	**1.06**	**1.87**	**2.13**	**2.08**	**2.29**	**11%**
Emera Maine		0.29	0.29	0.31	0.27	0.22	0.19	0.19	
Emera Energy[2]		0.34	0.69	0.89	0.14	0.11	0.51	0.15	
Other earnings[3]		0.10	0.32	-	0.49	-	0.10	(0.04)	
Consolidated adjusted EPS[1]	$	**1.96**	**2.23**	**2.26**	**2.77**	**2.46**	**2.88**	**2.59**	**5%**

[1] Excludes the effect of mark-to-market and impairment adjustments and, for 2017, exclude the revaluation of US non-regulated deferred income taxes
[2] Excludes one-time items
[3] Includes Algonquin equity earnings (2013-2016) and one-time items recorded in Corporate, NMGC and Emera Caribbean

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Emera Energy Quarterly Adjusted Earnings Contribution

Millions of Canadian dollars		Q1/18	Q2/18	Q3/18	Q4/18	Q1/19	Q2/19	Q3/19	Q4/19
Marketing and Trading	$	37	(5)	-	21	30	(20)	(19)	14
NEGG[(1)]		10	7	19	19	18	(2)	1	-
Maritimes Canada		4	(5)	(6)	(4)	0	(1)	-	(1)
Bear Swamp		4	5	6	8	4	4	4	4
Total (excl. MTM and loss on sale)	**$**	**55**	**2**	**19**	**44**	**52**	**(19)**	**(14)**	**17**
Net (loss)/gain on sale (recorded in Corporate)		-	-	-	-	(2)	(1)	-	-

Millions of CAD dollars		2012	2013	2014	2015	2016	2017	2018	2019
Marketing and Trading Earnings	$	10	31	68	44	25	19	53	5
Average (2012 to 2019)	$	32							
Average (2012 to 2019) excluding outliers	$	26							

[(1)] Q1/18 to Q1/19, inclusive, includes approximately $6 million per quarter of intercompany interest expense paid to Emera Corporate, where it was recorded as intercompany interest revenue. Emera Corporate financed the original acquisition off its balance sheet. No permanent debt financing was transferred with the sale of the gas plants.

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Non-GAAP Reconciliation

For the millions of Canadian dollars (except per share amounts)		Three months ended December 31		Year ended December 31	
		2019	2018	**2019**	2018
Net income attributable to common shareholders	$	**193**	231	**663**	710
GBPC impairment charge		**(34)**	-	**(34)**	-
After-tax mark-to-market gain (loss)		**82**	64	**76**	39
Adjusted net income attributable to common shareholders	$	**145**	167	**621**	671
Weighted average shares		**243**	235	**240**	233
Earnings per common share – basic	$	**0.79**	0.98	**2.76**	3.05
Adjusted earnings per common share – basic	$	**0.60**	0.71	**2.59**	2.88

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Emera's New Segmentation

Old	
Emera Florida and New Mexico	• Tampa Electric • Peoples Gas System • New Mexico Gas Company • Seacoast Gas (incl. in FL & NM other) • TECO Finance (incl. in FL & NM other) • New Mexico Gas Intermediate ("NMGI") (incl. in FL & NM other)
Nova Scotia Power	• Nova Scotia Power
Emera Maine	• Emera Maine
Emera Caribbean	• Emera Caribbean
Emera Energy	• Emera Energy Services • Emera Energy Generation • Bear Swamp (Equity Investment)
Corporate and Other	• Corporate • Brunswick Pipeline • M&NP (Equity Investment) • Emera Utility Services • Maritime Link (Equity Investment) • Labrador Island Link (Equity Investment)

New	
Florida Electric Utilities	• Tampa Electric
Canadian Electric Utilities	• Nova Scotia Power • Maritime Link (Equity Investment) • Labrador Island Link (Equity Investment)
Other Electric Utilities	• Emera Maine • Emera Caribbean
Gas Utilities and Infrastructure	• Peoples Gas System • New Mexico Gas Company, incl. NMGI • Seacoast Gas • Brunswick Pipeline • M&NP Pipeline (Equity Investment)
Other	• Corporate • TECO Finance • Emera Energy Services • Emera Energy Generation • Bear Swamp (Equity Investment) • Emera Utility Services

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Emera Segment Reconciliation

Old Segments	New Segments	Actual Q1/19	Actual Q2/19	Actual Q3/19	Actual Q4/19	Actual 2019	Actual Q1/18	Actual Q2/18	Actual Q3/18	Actual Q4/18	Actual 2018
Emera Florida & New Mexico		**114**	**143**	**153**	**109**	**519**	**90**	**97**	**140**	**101**	**428**
Tampa Electric	Florida Electric Utility	61	125	153	80	419	60	95	143	83	381
Peoples Gas	Gas Utilities and Infrastructure	24	18	14	16	72	19	15	12	16	62
NMGC	Gas Utilities and Infrastructure	31	10	(1)	22	62	22	(3)	(7)	13	25
Seacoast	Gas Utilities and Infrastructure	2	2	2	2	8	2	2	2	2	8
TECO Corporate	Other	(4)	(12)	(15)	(11)	(42)	(13)	(12)	(10)	(13)	(48)
Nova Scotia Power Inc.	Canadian Utilities	**71**	**19**	**13**	**35**	**138**	**65**	**23**	**15**	**28**	**131**
Emera Maine	Other Utilities	**10**	**12**	**15**	**10**	**47**	**10**	**6**	**17**	**11**	**44**
Emera Caribbean	Other Utilities	**6**	**11**	**8**	**4**	**29**	**5**	**12**	**14**	**14**	**45**
Emera Energy	Other	**52**	**(19)**	**(14)**	**17**	**36**	**55**	**2**	**19**	**44**	**120**
Corporate & Other		**(29)**	**(36)**	**(53)**	**(29)**	**(147)**	**(23)**	**(29)**	**(14)**	**(31)**	**(97)**
ENL (NSPML and LIL)	Canadian Utilities	25	23	20	23	91	25	25	21	16	87
Pipelines	Gas Utilities and Infrastructure	10	10	10	12	42	10	11	8	12	42
Corporate	Other	(63)	(69)	(84)	(64)	(280)	(58)	(66)	(43)	(53)	(221)
Emera Utility Services	Other	(1)	-	1	-	-	-	1	-	(6)	(5)
Total		**224**	**130**	**122**	**145**	**621**	**202**	**111**	**191**	**167**	**671**
WA Shares		236	239	241	243	240	231	233	234	235	233
Adj. EPS		**0.95**	**0.54**	**0.51**	**0.60**	**2.59**	**0.87**	**0.48**	**0.82**	**0.71**	**2.88**

New Segments	Actual Q1/19	Actual Q2/19	Actual Q3/19	Actual Q4/19	Actual 2019	Actual Q1/18	Actual Q2/18	Actual Q3/18	Actual Q4/18	Actual 2018
Florida Utility	61	125	153	80	419	60	95	143	83	381
Canadian Utilities	96	42	33	58	229	90	48	36	44	218
Other Electric	16	23	23	14	76	15	18	31	25	89
Gas	67	40	25	51	183	53	25	15	43	136
Other	(16)	(100)	(112)	(58)	(286)	(16)	(75)	(34)	(28)	(153)
Total	**224**	**130**	**122**	**145**	**621**	**202**	**111**	**191**	**167**	**671**

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Forward Looking Information and Non-GAAP Measures

Forward-Looking Information

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations are discussed in the Business Overview and Outlook section of Management's Discussion and Analysis ("MD&A") and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; future dividend growth; timing and costs associated with certain capital investment; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats, such as the COVID-19 novel coronavirus ("COVID-19") pandemic; market energy sales prices; labour relations; and availability of labour and management resources.

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

Nothing in this document should be construed as an offer or sale of securities of Emera or any other person.

Non-GAAP Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. Refer to the Non-GAAP Financial Measures section of our MD&A for further discussion of these items.

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Business Update

Scott Balfour
President and CEO

Emera's COVID-19 Response

Health and safety of our employees, customers and communities is the top priority

Crisis Management Planning

- Activated cross-functional pandemic team
- Leveraging extensive experience in emergency planning

Employees

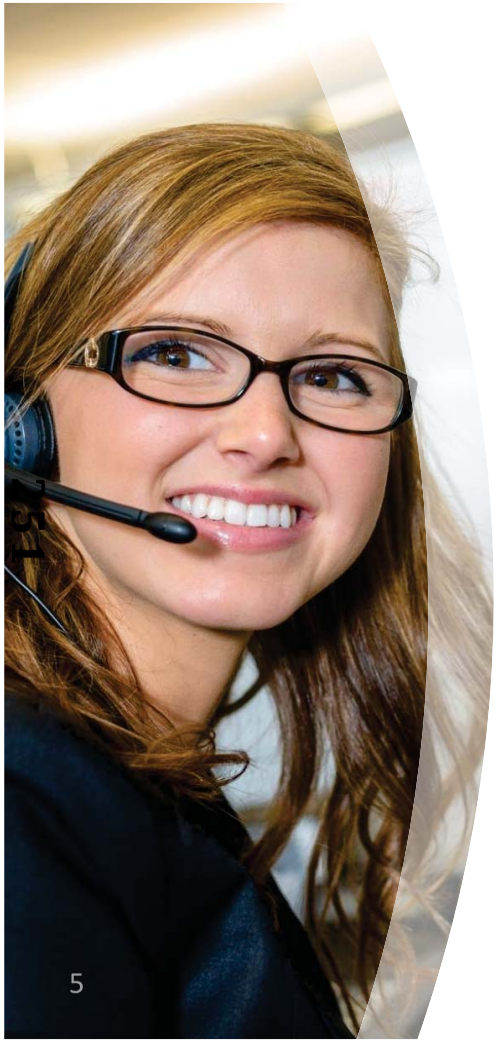
- Many employees having been working from home since early March
- Use of social distancing protocols along with appropriate PPE
- Established health screening locations at critical function work areas
- Control centers split between primary and backup locations and utilizing staggered shift start times
- Minimizing potential exposure with the public



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Emera's Support for Recovery

Customers

- Disconnections due to overdue accounts were suspended at all Emera's utilities
- Connecting customers to agencies providing financial support
- Tampa Electric customers will receive an accelerated flow back of fuel savings to reduce customer bills (June to December)

Community

- Emera's companies have donated ~$4 million to organizations dedicated to providing critical aid for the most vulnerable in our communities
- Open communication with government officials and regulatory commissions

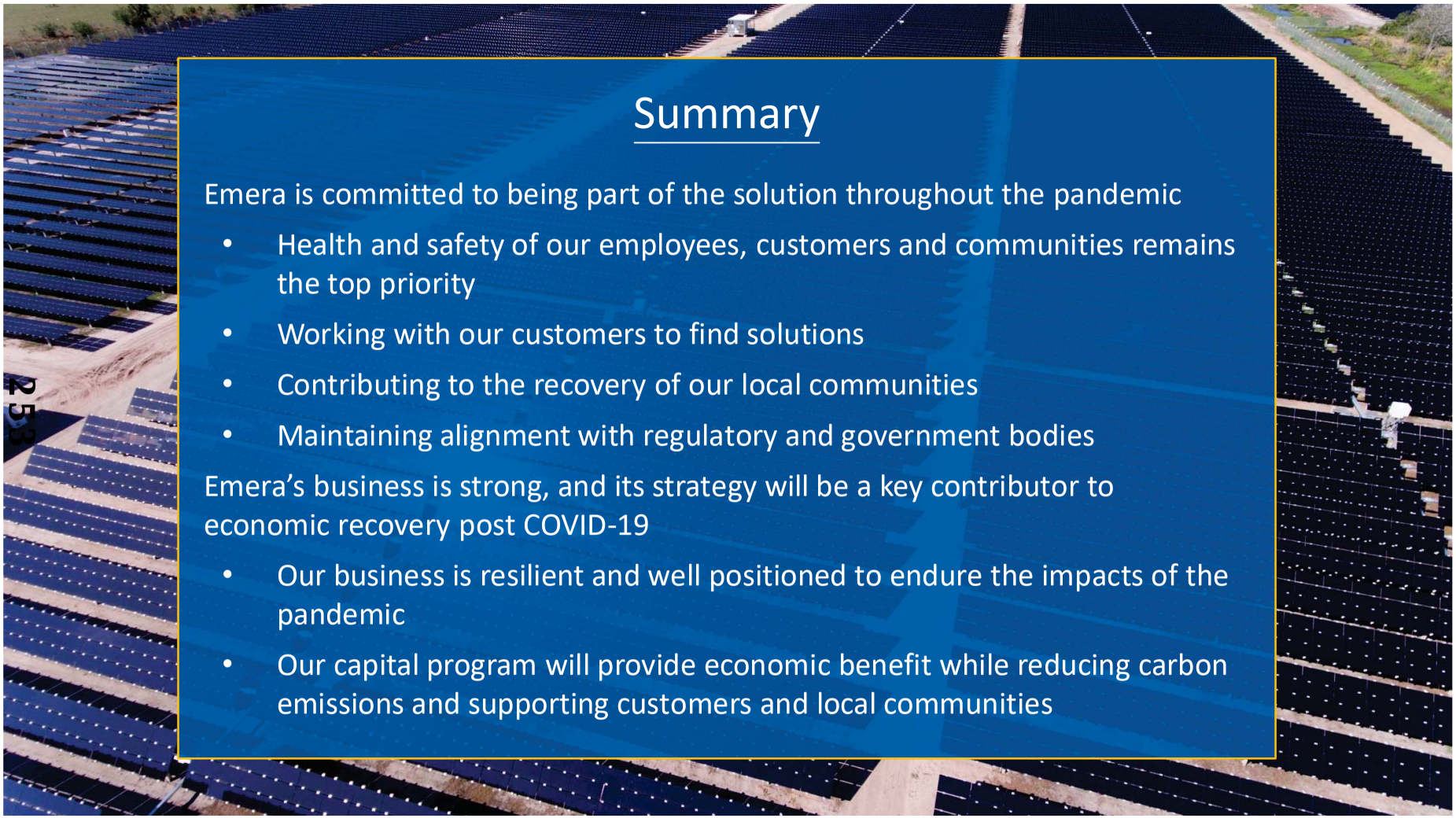
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Emera's Resiliency

- Emera is performing well with minimal COVID-19 impact on the Q1 financial results
- Customer mix is heavily weighted to the residential customer class with less dependence on industrial and commercial customers
- Emera Maine transaction has provided significant liquidity to manage through the pandemic and beyond
- Bad debt recovery has been strong through other periods of economic stress
- Large capital projects have been prioritized and are advancing with additional health and safety precautions
- Emera's strategy remains relevant despite uncertainties related to COVID-19



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Summary

Emera is committed to being part of the solution throughout the pandemic

- Health and safety of our employees, customers and communities remains the top priority
- Working with our customers to find solutions
- Contributing to the recovery of our local communities
- Maintaining alignment with regulatory and government bodies

Emera's business is strong, and its strategy will be a key contributor to economic recovery post COVID-19

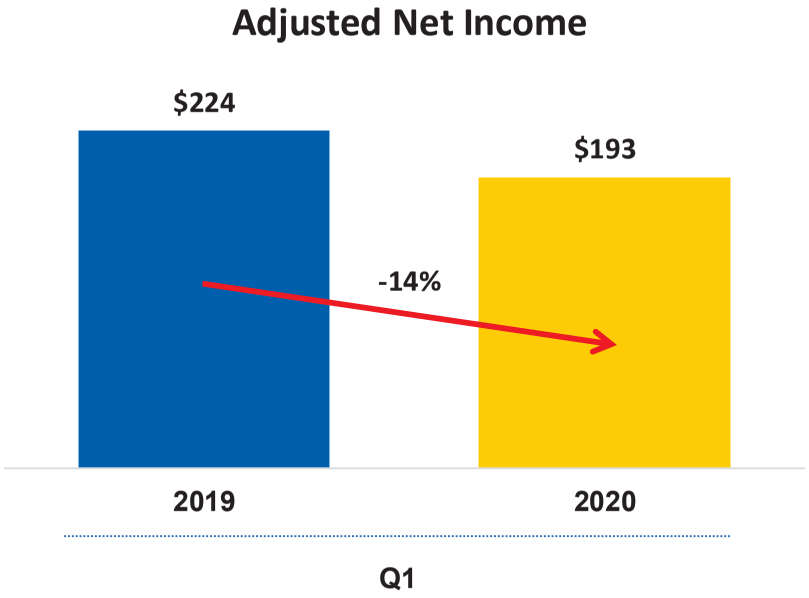
- Our business is resilient and well positioned to endure the impacts of the pandemic
- Our capital program will provide economic benefit while reducing carbon emissions and supporting customers and local communities

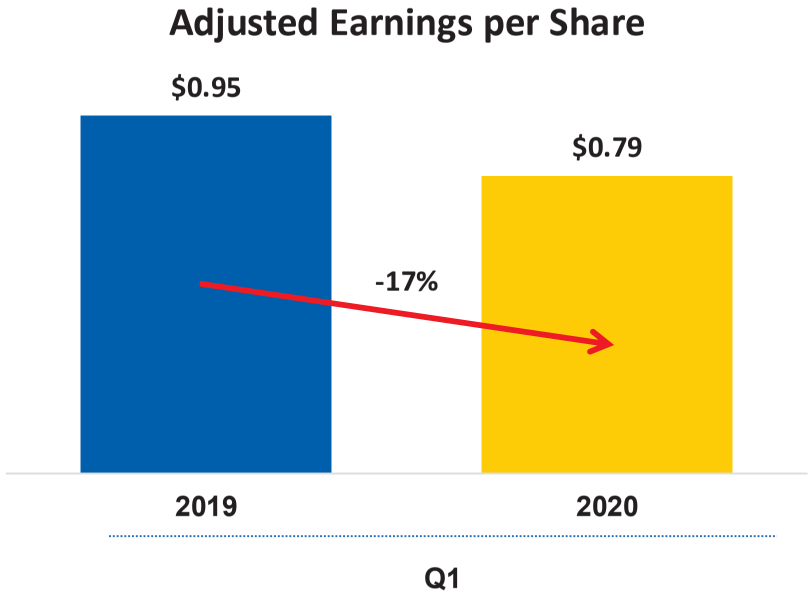
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Greg Blunden
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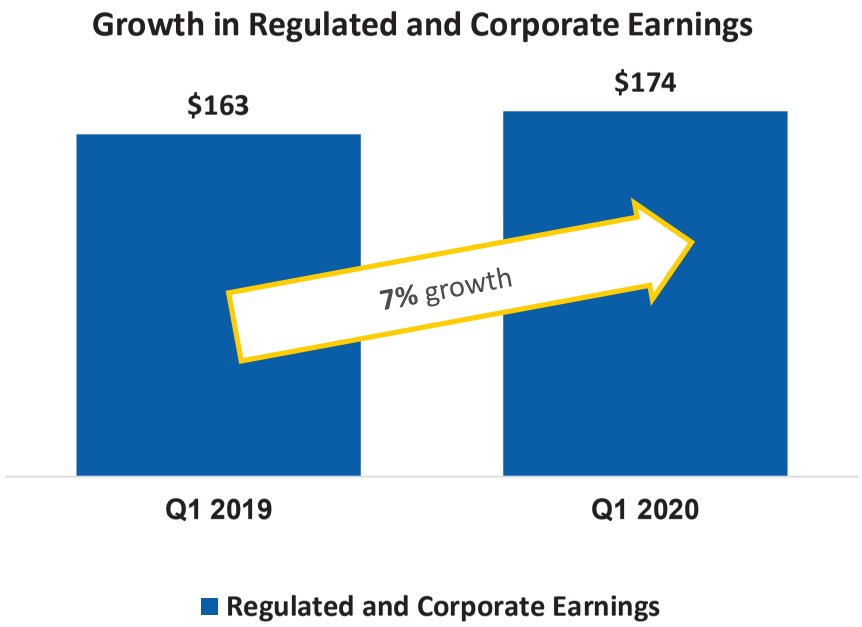


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Strong Performance by Regulated Businesses



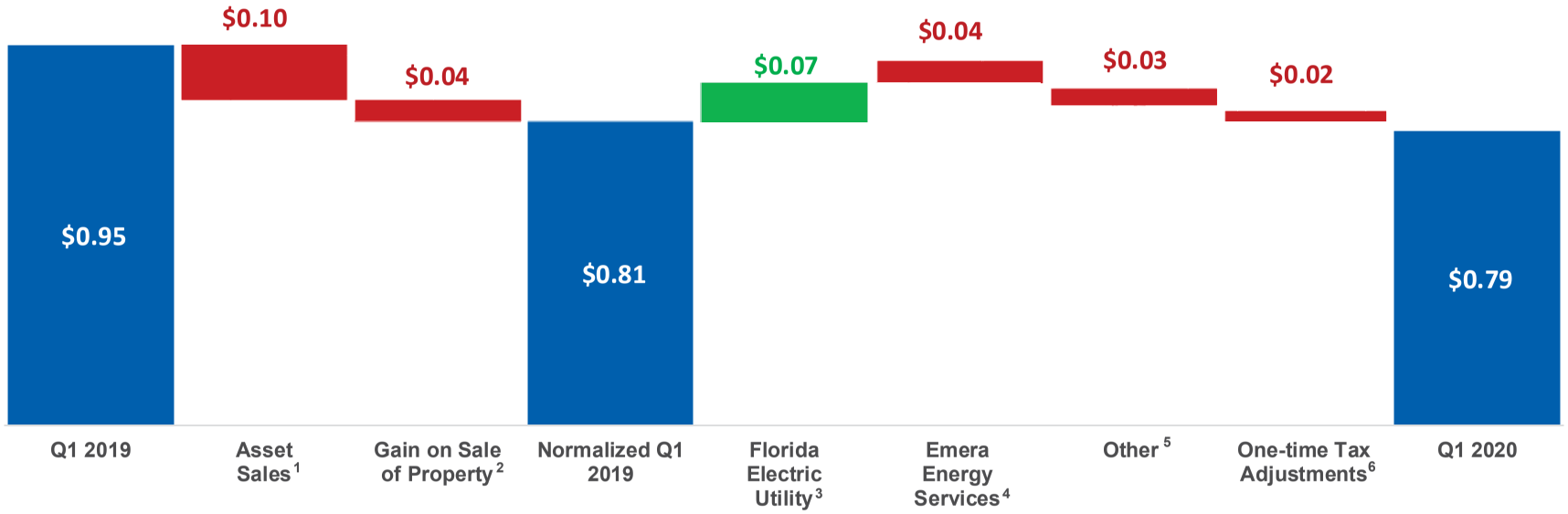
Emera's earnings quality continues to improve as regulated earnings grow

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Key Drivers of Q1 2020 Adjusted EPS



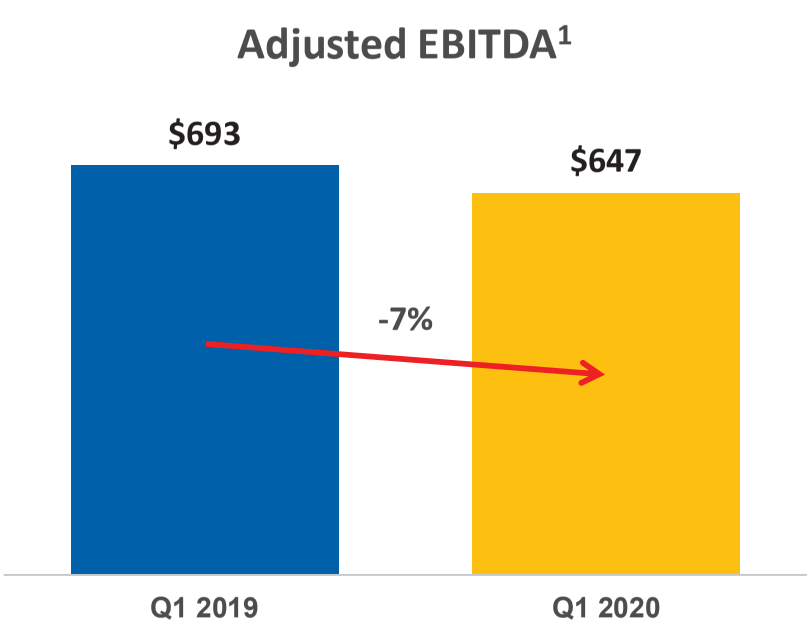
[1] Decreased earnings from Emera Energy due to sale of NEGG and Bayside
[2] One-time gain related to the sale of property in Florida
[3] Increased earnings due to favourable weather, customer growth and higher contribution from solar projects
[4] Decreased earnings from marketing and trading due to unfavorable market conditions compared to Q1 2019
[5] Other immaterial variances including FX and share dilution
[6] Decreased earnings from the change in the Nova Scotia corporate tax rate partially offset by the recognition of income tax recovery deferred as a regulatory liability at BLPC

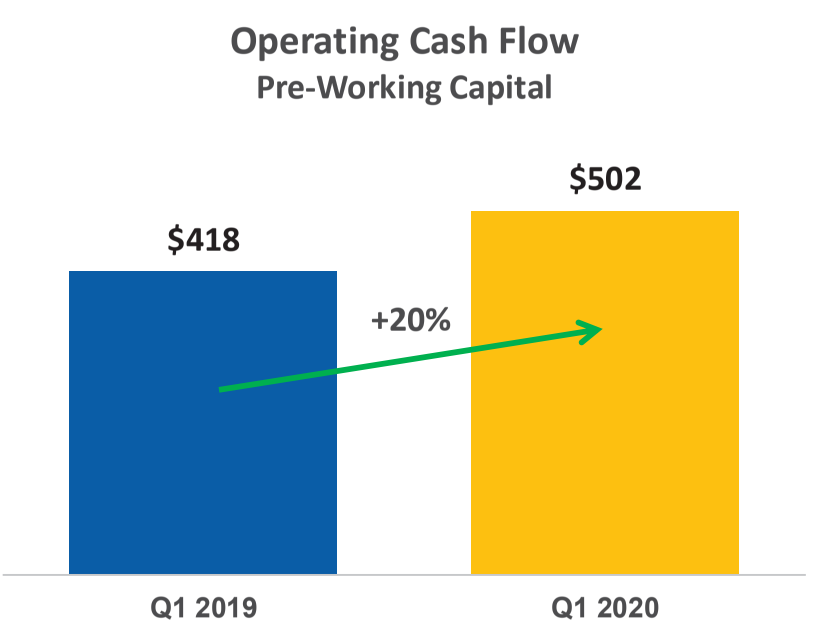
Emera

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Adjusted EBITDA and Operating Cash Flow





[1] Refer to the Q1 2020 Emera financial statements and MD&A for a reconciliation of EBITDA to reported net income

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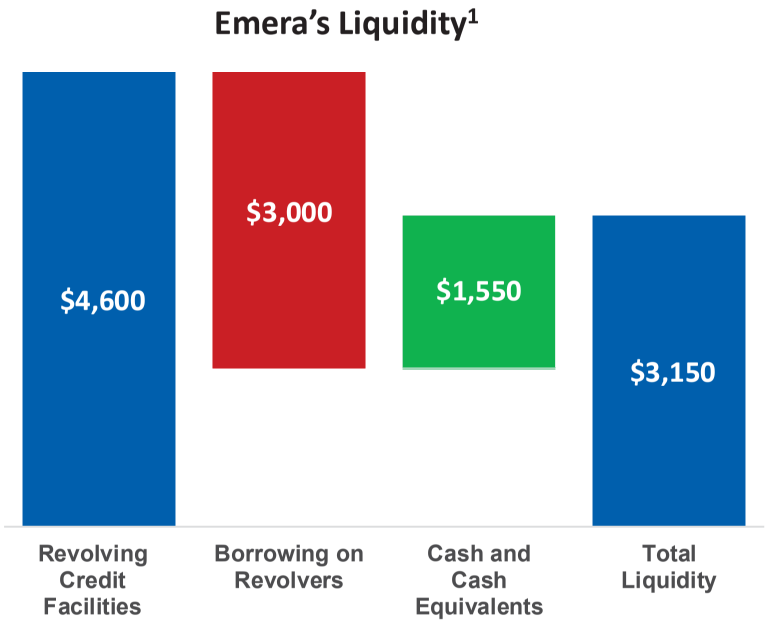


Emera Maine Transaction

- Proceeds of US$963 million were received on March 24th
- 2018 asset sale program raised $2.2 billion in capital
- Proceeds from the sale of Emera Maine will be used to fund capital program and repay holdco debt
- Thank you to Emera Maine employees and good luck to ENMAX in the future

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Emera's Liquidity



- Proceeds from the sale of Emera Maine bolstered Emera's liquidity position
- NSP issued a $300 million, 30-year private placement in April providing additional liquidity
- Emera and its affiliates have no significant long-term debt maturities in 2020
- Pension plans are well funded with no significant short-term funding requirements

~$3.2 billion of liquidity as at March 31st

[1] As at March 31, 2020, in millions of Canadian dollars

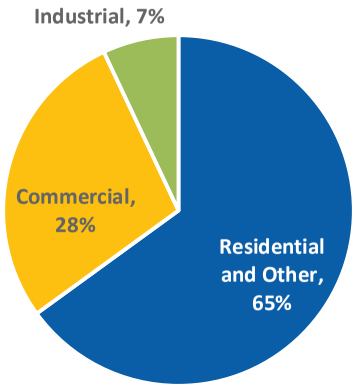
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Emera's Customer Profile

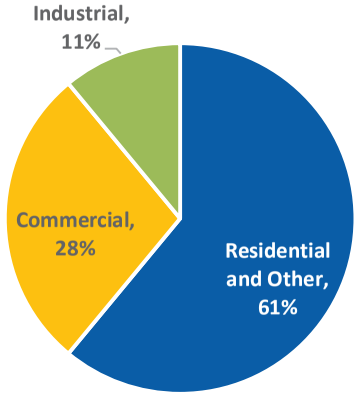
Tampa Electric Company[1]

% Contribution to Fixed Cost Recovery



Nova Scotia Power[1]

% Contribution to Fixed Cost Recovery



Emera's largest utilities are primarily residential load utilities with smaller contributions from C&I customers to fixed cost recovery

[1] Based on 2019 load profiles, revenues, and cost of fuel and purchased power

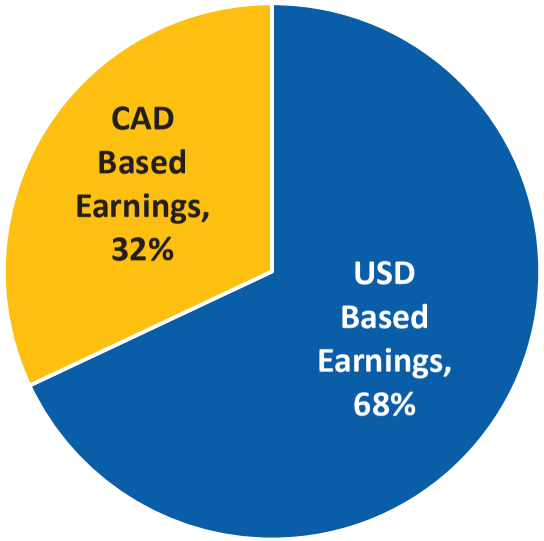
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Foreign Exchange Exposure



- Strong USD provides potential upside
- 68% of Emera's earnings are USD based[1]
- FX hedges have been put in place for a portion of 2020 and 2021 earnings
  - 2020 - $200 million at $1.337
  - 2021 - $100 million at $1.423
- Directionally, a $0.01 change in the USD/CAD FX rate is approximately $0.005 to $0.01 of EPS on an annualized basis

[1] Based on 2019 adjusted earnings (excluding Emera Maine), using an average exchange rate of $1.33

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Summary

- 7% growth from our regulated utilities to start the year
- Improved cash flow from operations relative to Q1 2019
- Emera Maine proceeds bolster Emera's liquidity position and complete the 2018 asset sales program
- Proven track record of working with customers to manage bad debts
- Strong US dollar and customer mix offer mitigating factors to COVID-19 load impacts

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Upcoming Investor Events
Annual General Meeting
Friday, June 5, 2020
Virtual
Halifax, Nova Scotia
Emera
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Emera Energy Quarterly Adjusted Earnings Contribution

Millions of Canadian dollars		Q1/18	Q2/18	Q3/18	Q4/18	Q1/19	Q2/19	Q3/19	Q4/19	Q1/20
Marketing and Trading	$	37	(5)	-	21	30	(20)	(19)	14	19
NEGG[1]		10	7	19	19	18	(2)	1	-	-
Maritimes Canada		4	(5)	(6)	(4)	0	(1)	-	(1)	(2)
Bear Swamp		4	5	6	8	4	4	4	4	4
Total (excl. MTM and loss on sale)	**$**	**55**	**2**	**19**	**44**	**52**	**(19)**	**(14)**	**17**	**21**
Net (loss)/gain on sale (recorded in Corporate)		-	-	-	-	(2)	(1)	-	-	-

Millions of CAD dollars		2012	2013	2014	2015	2016	2017	2018	2019
Marketing and Trading Earnings	$	10	31	68	44	25	19	53	5
Average (2012 to 2019)	$	32							
Average (2012 to 2019) excluding outliers	$	26							

[1] Q1/18 to Q1/19, inclusive, includes approximately $6 million per quarter of intercompany interest expense paid to Emera Corporate, where it was recorded as intercompany interest revenue. Emera Corporate financed the original acquisition off its balance sheet. No permanent debt financing was transferred with the sale of the gas plants.

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Non-GAAP Reconciliation

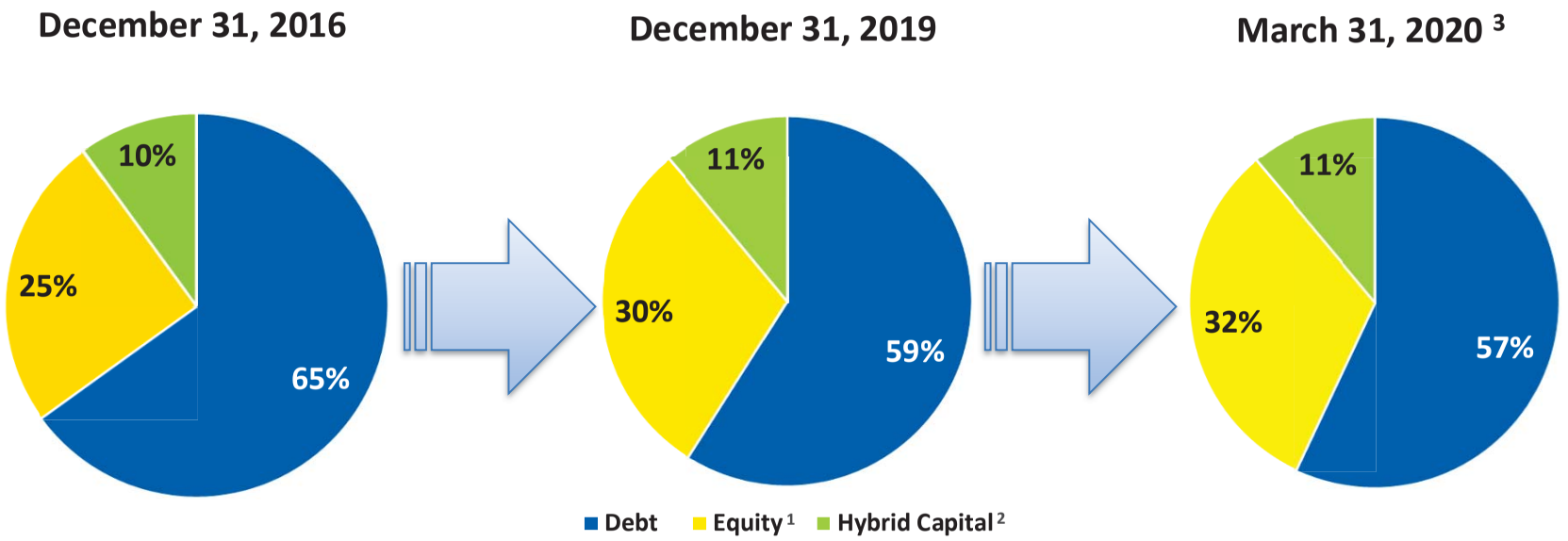
For the millions of Canadian dollars (except per share amounts)		Three months ended March 31	
		2020	2019
Net income attributable to common shareholders	$	**523**	312
Gain on sale and impairment charges, net of taxes		**298**	-
After-tax mark-to-market gain		**32**	88
Adjusted net income attributable to common shareholders	$	**193**	224
Weighted average shares		**245**	236
Earnings per common share – basic	$	**2.14**	1.32
Adjusted earnings per common share – basic	$	**0.79**	0.95

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Strengthening the Balance Sheet



Target of 55% Debt, 35% Equity and 10% Preferred Equity

[1] Equity includes the NCI and excludes AOCI
[2] Includes preferred shares and hybrid bonds
[3] Debt is calculated net of Emera Maine sale proceeds, the majority of which are held in cash as of March 31, 2020

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Second Quarter 2020

August 12, 2020

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Forward Looking Information and Non-GAAP Measures

Forward-Looking Information

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations are discussed in the "Business Overview and Outlook" section of the Management's Discussions and Analysis ("MD&A") and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; future dividend growth; timing and costs associated with certain capital investment; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats, such as the COVID-19 novel coronavirus ("COVID-19") pandemic; market energy sales prices; labour relations; and availability of labour and management resources.

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

Nothing in this document should be construed as an offer or sale of securities of Emera or any other person.

Non-GAAP Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. Refer to the Non-GAAP Financial Measures section of our MD&A for further discussion of these items.

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Business Update

Scott Balfour
President and CEO

COVID-19 Update

Health and safety of our employees, customers and communities continues to be our top priority

- Emera remains strong and is performing at a high-level without disruption
- Continue to operate under Emera's crisis management plan
- Assessing responsible re-entry policies in connection with local health authorities' and industry guidelines
- Working with vulnerable customers to establish payments plans and facilitate financial aid



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Emera's Resiliency

- Emera is performing well and there has not been a material impact to consolidated earnings to date
- Customer mix is heavily weighted to the residential customer class with less dependence on industrial and commercial customers
- Emera's balance sheet and cash flows have remained strong
- Capital program remains intact and major projects are continuing without any major disruptions
- Emera's strategy continues to provide a roadmap for growth

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Regulatory Update

- Emera operates in high quality regulatory jurisdictions
- Regulatory filings have advanced despite the impacts of COVID-19
- Stipulation approved for the storm protection plan at Tampa Electric
- Emera's gas utilities have filed for regulatory relief for COVID related impacts



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Summary

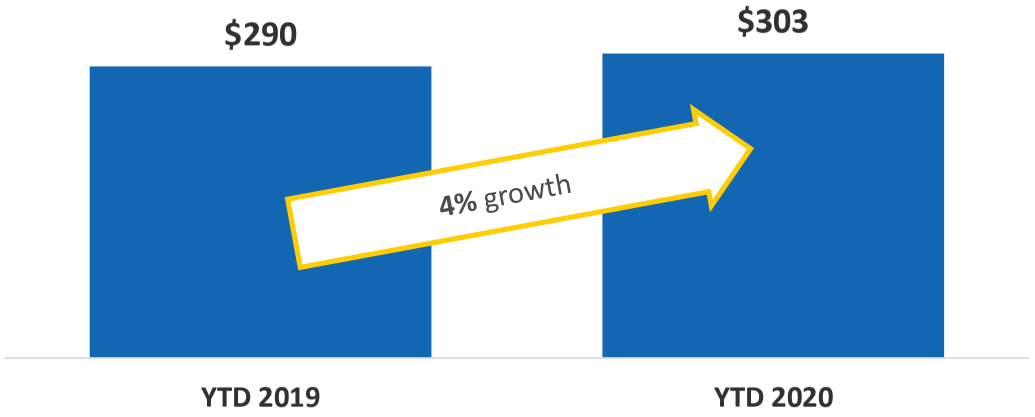
- Health and safety of our employees, customers and communities remains the top priority
- Strength and diversity of Emera's businesses have mitigated the impacts of COVID-19 for the year-to-date
- Working with vulnerable customers to establish payment plans and facilitate financial aid

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Financial Results

Greg Blunden
CFO

Strong YTD Performance by Regulated Businesses[1]



Emera's earnings quality continues to improve as regulated earnings grow

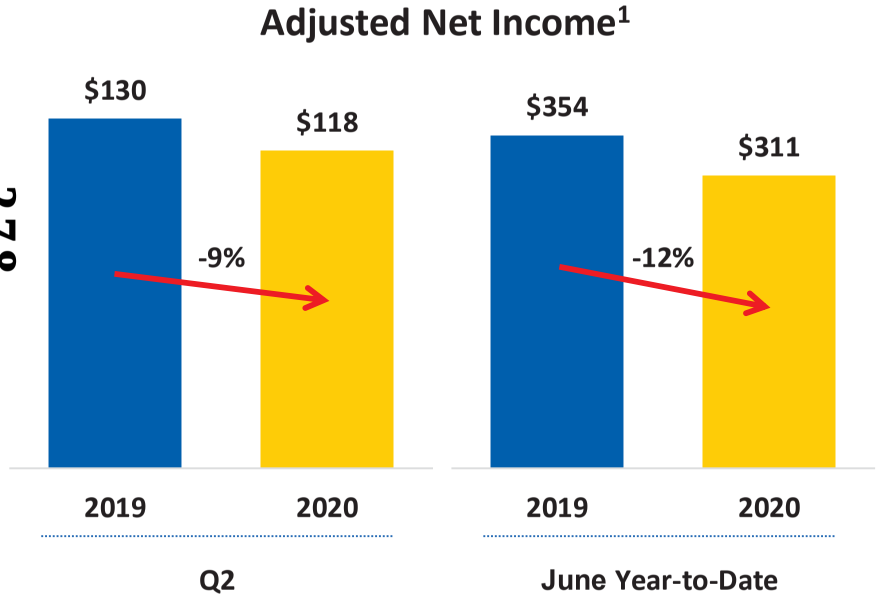
[1] Regulated and corporate earnings in millions of CAD (excluding Emera Maine and the impacts of preferred dividend timing in Q2 2020)

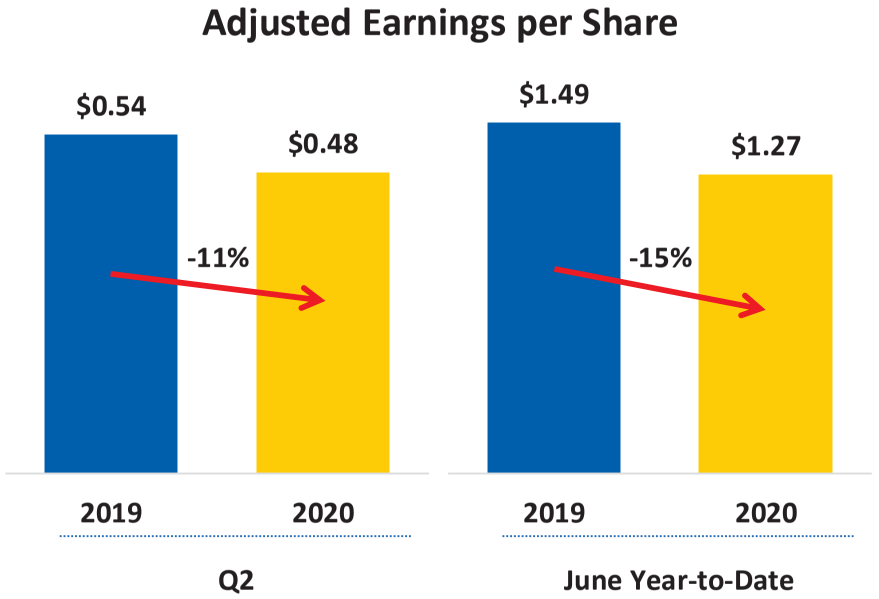
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Adjusted Earnings and Adjusted EPS





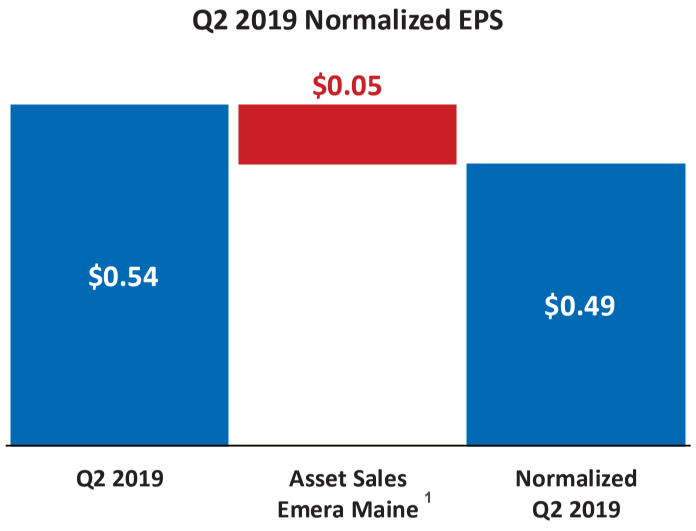
[1] In millions of dollars

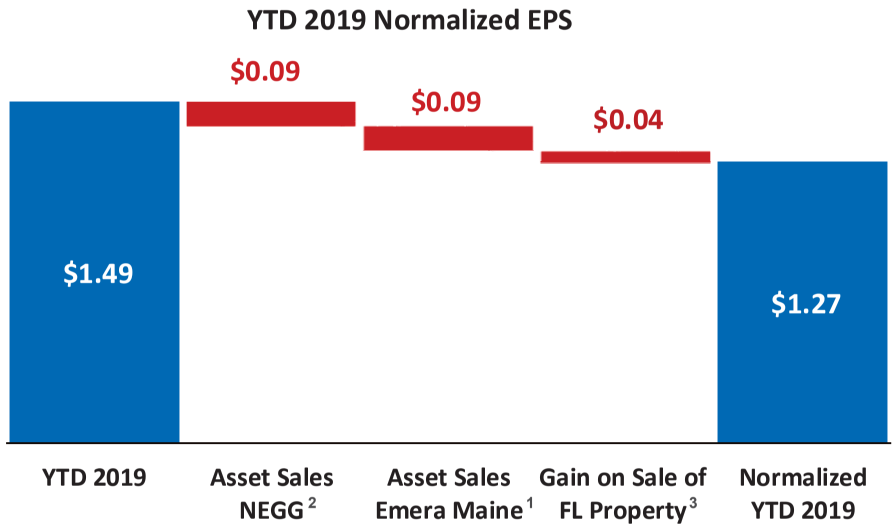
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Normalizing EPS for Asset Sales





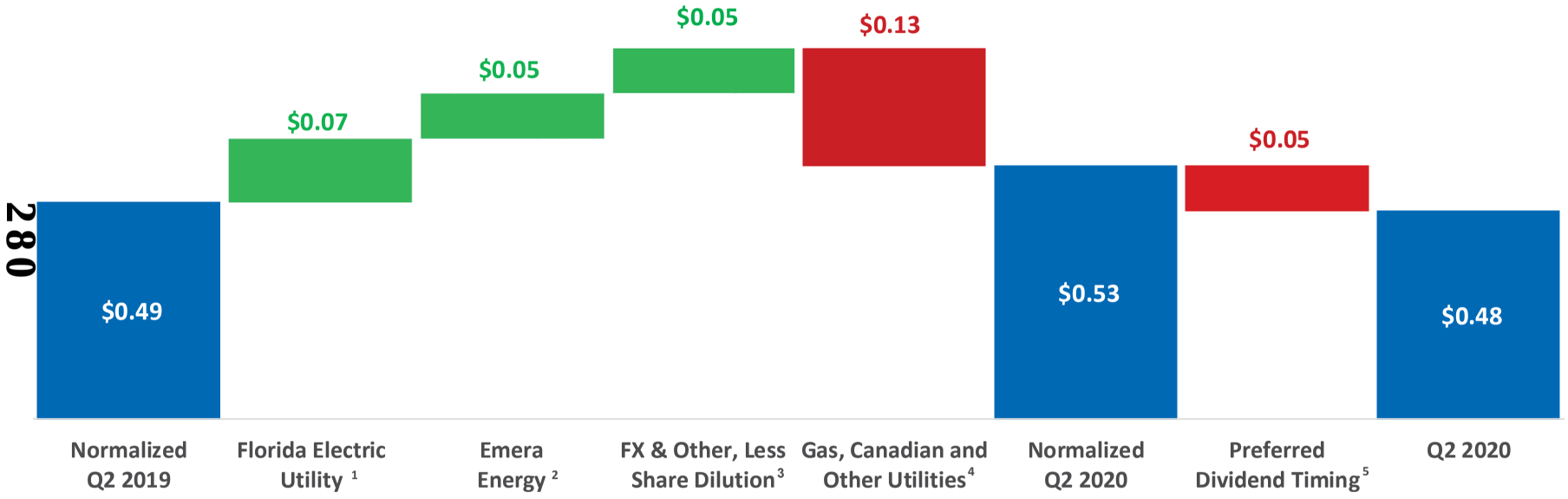
[1] Emera Maine was sold in March 2020
[2] Emera unregulated gas plants were sold in Q1 2019
[3] Emera recognized a $10 million gain on the sale of a property in Florida in Q1 2019

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Key Drivers of Q2 2020 Adjusted EPS



[1] Higher earnings due to customer growth, increased mix from residential sales, higher AFUDC, lower OM&G, the in-service of solar generation projects, lower depreciation and amortization expense as a result of a regulatory settlement, and favourable weather

[2] Primarily due to increased earnings from marketing and trading due to more favourable market conditions compared to Q2 2019

[3] Includes the impact of foreign exchange (+$0.01), other items (+$0.05) and share dilution (-$0.01)

[4] Decreased earnings from Canadian Electric Utilities (-$0.02) and Gas Utilities and Infrastructure (-$0.06) and Other Electric Utilities excluding Emera Maine (-$0.05)

[5] Timing of preferred share dividend declaration in Q2 2020 as compared to Q3 2019

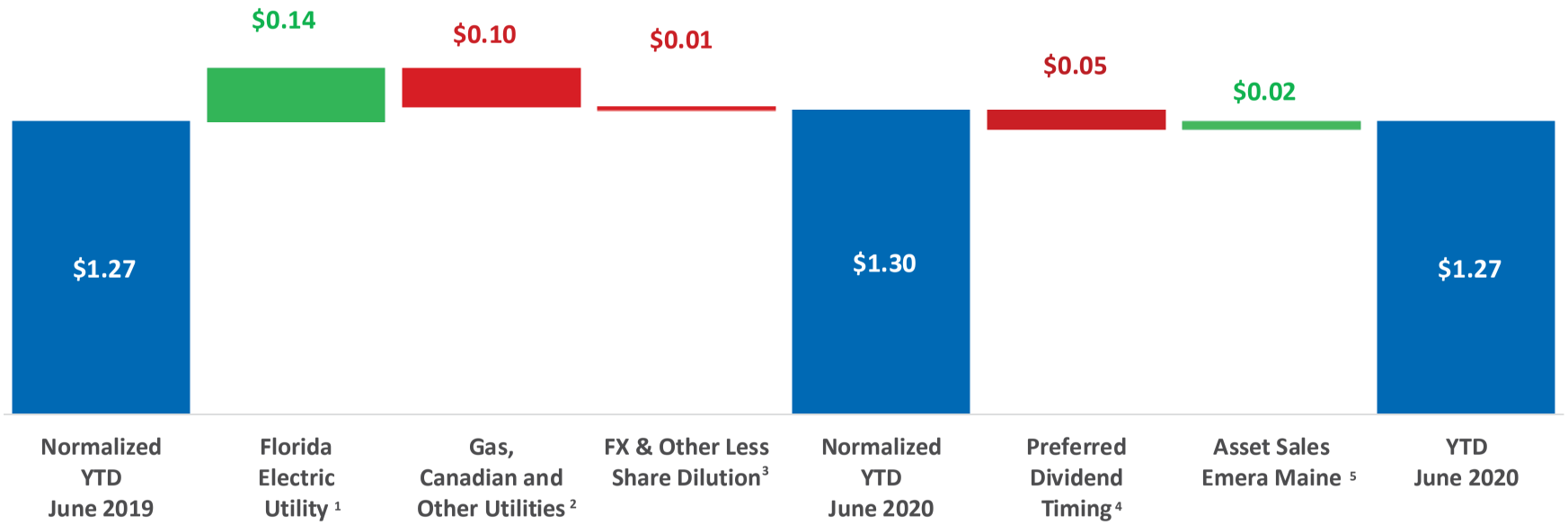
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Key Drivers of Year-to-Date Adjusted EPS



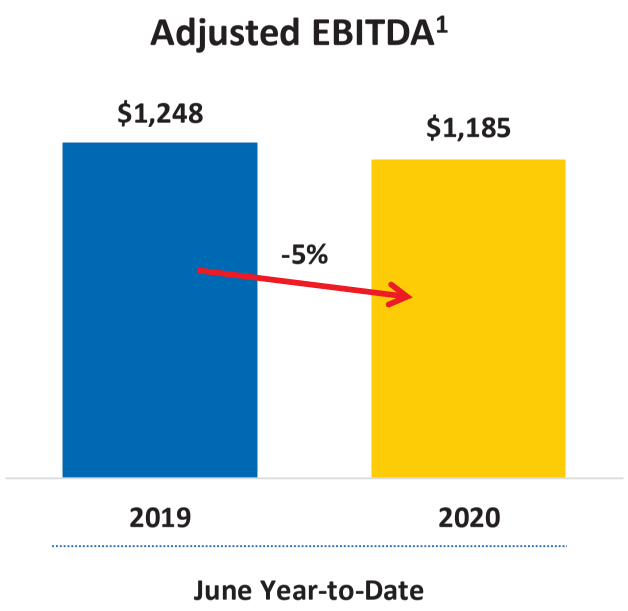
[1] Higher base revenues related to favourable weather in Q1, higher AFUDC, lower OM&G, customer growth, the in-service of solar generation projects, and lower depreciation and amortization expense as a result of a regulatory settlement
[2] Consists of Gas Utilities and Infrastructure ($-0.04), Canadian Electric Utilities ($-0.04) and Other Electric Utilities excluding Emera Maine ($-0.02)
[3] Includes impacts of FX ($0.02), other ($0.01) and share dilution ($-0.04)
[4] Timing of preferred share dividend declaration in Q2 2020 as compared to Q3 2019
[5] Emera Maine earnings for Q1 2020, sold in March 2020

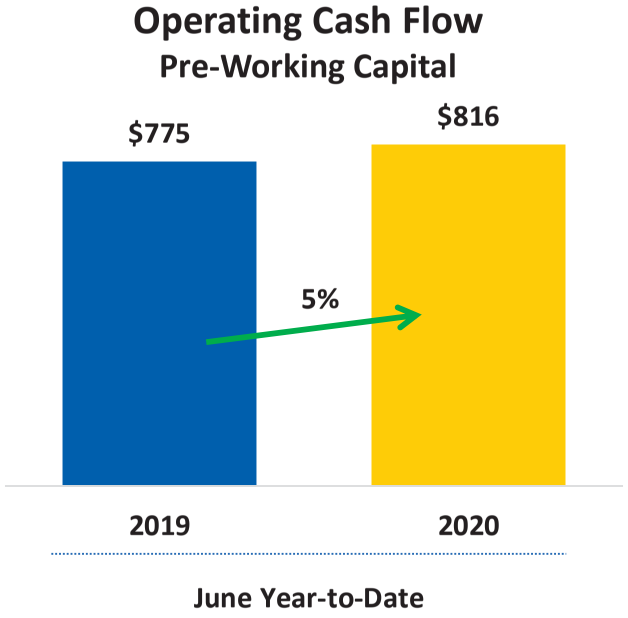
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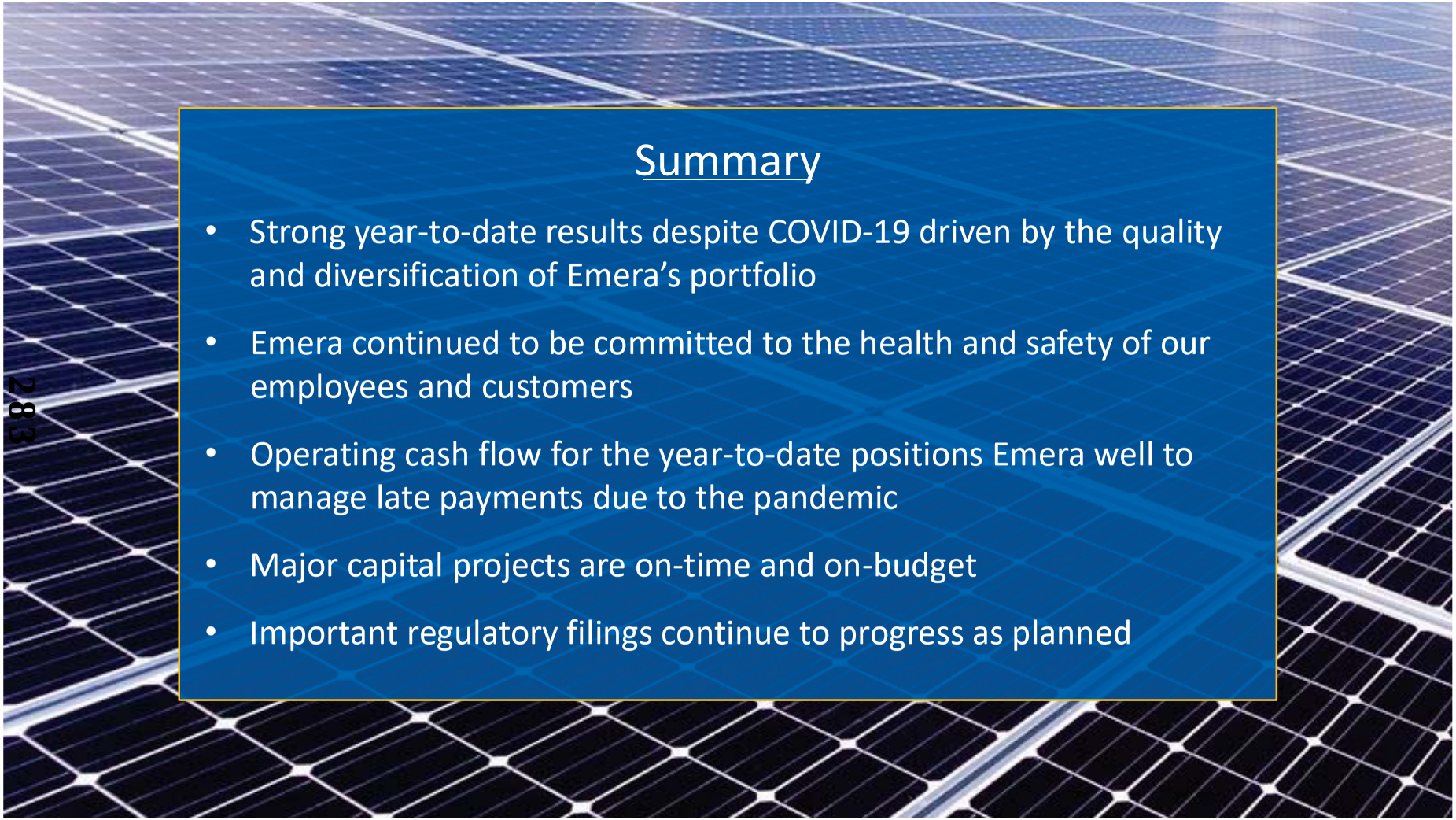
Adjusted EBITDA and Operating Cash Flow





[1] Refer to the Q2 2020 Emera financial statements and MD&A for a reconciliation of EBITDA to reported net income

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Summary

- Strong year-to-date results despite COVID-19 driven by the quality and diversification of Emera's portfolio
- Emera continued to be committed to the health and safety of our employees and customers
- Operating cash flow for the year-to-date positions Emera well to manage late payments due to the pandemic
- Major capital projects are on-time and on-budget
- Important regulatory filings continue to progress as planned

TAMPA ELECTRIC COMPANY
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Upcoming Investor Events
Expected Q3/20 Results & Conference Call
Friday, November 13, 2020
Emera

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Emera Energy Quarterly Adjusted Earnings Contribution

Millions of Canadian dollars		Q1/18	Q2/18	Q3/18	Q4/18	Q1/19	Q2/19	Q3/19	Q4/19	Q1/20	Q2/20
Marketing and Trading	$	37	(5)	-	21	30	(20)	(19)	14	19	(11)
NEGG[1]		10	7	19	19	18	(2)	1	-	-	-
Maritimes Canada		4	(5)	(6)	(4)	0	(1)	-	(1)	(2)	-
Bear Swamp		4	5	6	8	4	4	4	4	4	4
Total (excl. MTM and loss on sale)	**$**	**55**	**2**	**19**	**44**	**52**	**(19)**	**(14)**	**17**	**21**	**(7)**
Net (loss)/gain on sale (recorded in Corporate)		-	-	-	-	(2)	(1)	-	-	-	-

Millions of CAD dollars		2012	2013	2014	2015	2016	2017	2018	2019
Marketing and Trading Earnings	$	10	31	68	44	25	19	53	5
Average (2012 to 2019)	$	32							
Average (2012 to 2019) excluding outliers	$	26							

[1] Q1/18 to Q1/19, inclusive, includes approximately $6 million per quarter of intercompany interest expense paid to Emera Corporate, where it was recorded as intercompany interest revenue. Emera Corporate financed the original acquisition off its balance sheet. No permanent debt financing was transferred with the sale of the gas plants.

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Non-GAAP Reconciliation

For the millions of Canadian dollars (except per share amounts)		Three months ended June 30		Six months ended June 30	
		2020	2019	**2020**	2019
Net income (loss) attributable to common shareholders	**$**	**58**	103	**581**	415
Gain (loss) on sale and impairment charges, net of taxes		**(15)**	-	**283**	-
After-tax mark-to-market gain (loss)		**(45)**	(27)	**(13)**	61
Adjusted net income attributable to common shareholders	**$**	**118**	130	**311**	354
Weighted average shares		**247**	239	**246**	238
Earnings per common share – basic	**$**	**0.24**	0.43	**2.37**	1.75
Adjusted earnings per common share – basic	**$**	**0.48**	0.54	**1.27**	1.49

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Third Quarter 2020

November 13, 2020

Emera

Forward Looking Information and Non-GAAP Measures

Forward-Looking Information

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations are discussed in the "Business Overview and Outlook" section of the Management's Discussions and Analysis ("MD&A") and may also include: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; future dividend growth; timing and costs associated with certain capital investment; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats, such as the COVID-19 novel coronavirus ("COVID-19") pandemic; market energy sales prices; labour relations; and availability of labour and management resources.

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

Nothing in this document should be construed as an offer or sale of securities of Emera or any other person.

Non-GAAP Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. Refer to the Non-GAAP Financial Measures section of our MD&A for further discussion of these items.

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Business Update

Scott Balfour
President and CEO

COVID-19 Update

Health and safety of our employees, customers and communities continues to be our top priority

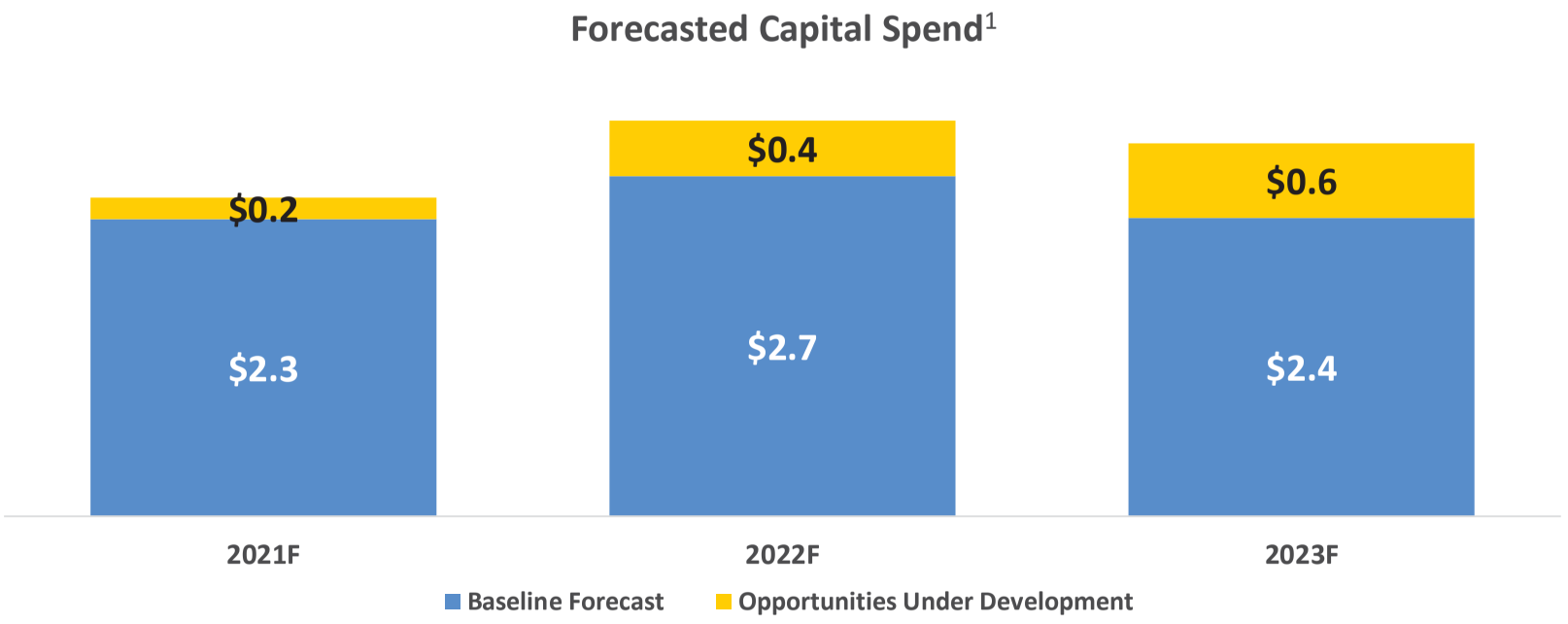
- Emera remains strong and is performing at a high-level without disruption
- Working with vulnerable customers to establish payments plans and facilitate financial aid
- Large capital projects have been prioritized and are advancing with additional health and safety precautions
- Emera's strategy continues to provide a roadmap for growth



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Plan to Invest Between $7.4B to $8.6B in Rate Base



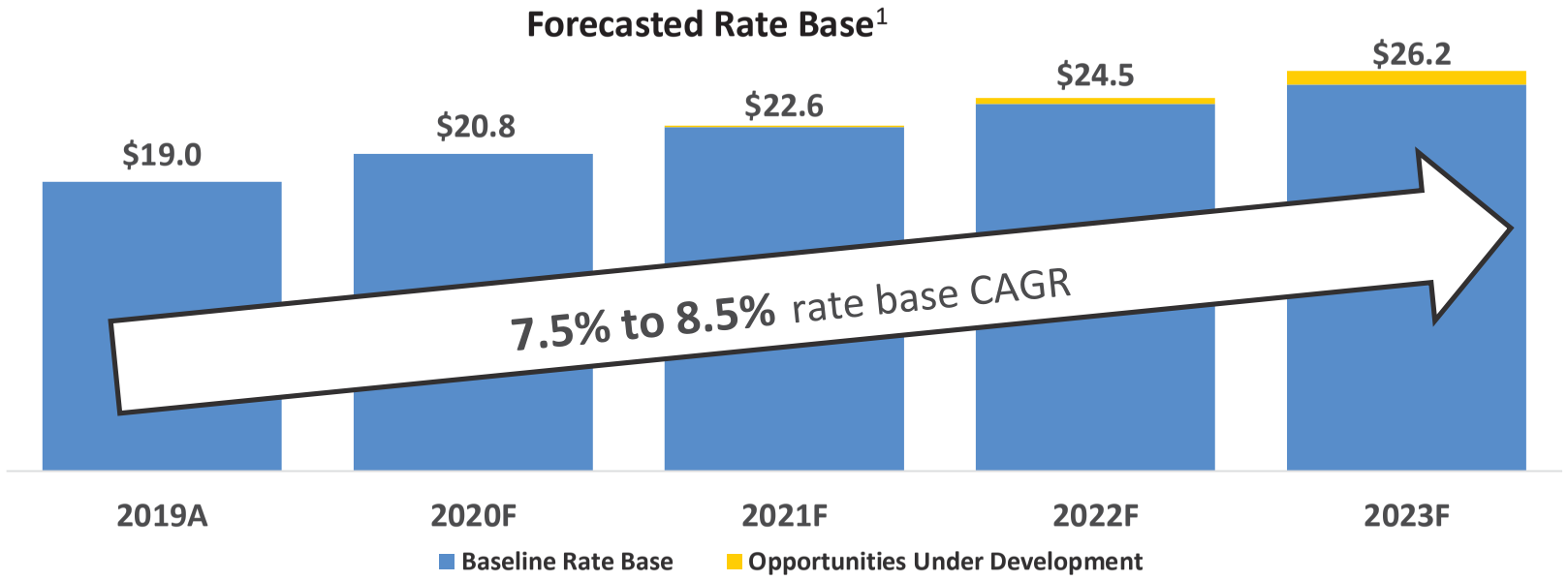
[1] In billions of Canadian dollars. US dollar denominated capex is translated at a forecasted average USD/CAD exchange rate of 1.33 in 2021-2023. Capital spend forecast by affiliate can be found in the appendix.

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Capital Program Drives Future Rate Base Growth



[1] 2019 actuals exclude Emera Maine. Average total rate base in billions of Canadian dollars. U.S. dollar denominated rate base is translated at a forecasted exchange rate of 1.33 in 2020-2023. Details by affiliate can be found in the appendix.

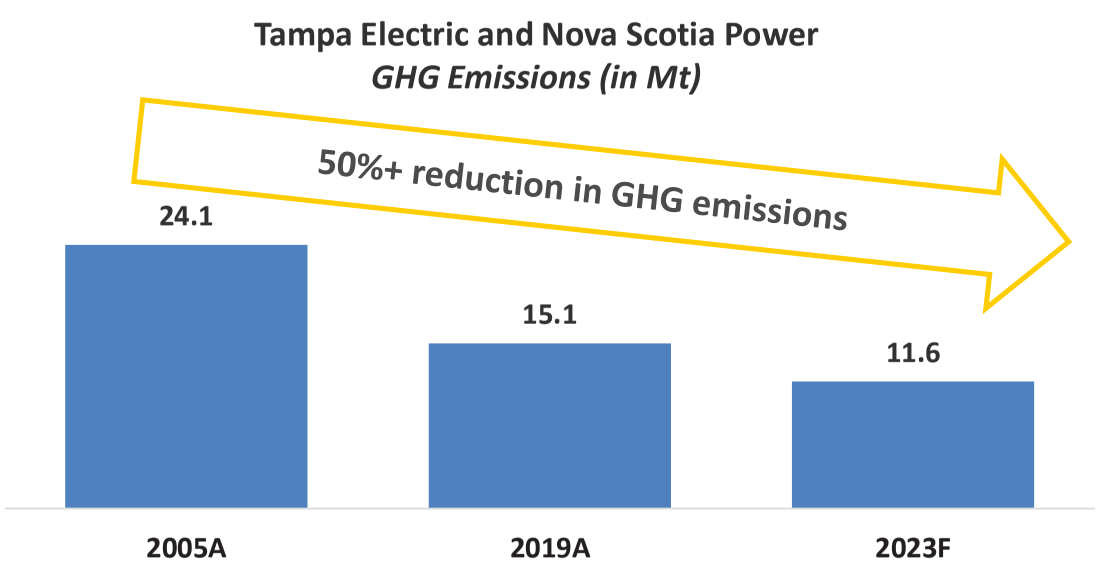
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Emera's Decarbonization Strategy in Action

Emera's strategy, which is focused on decarbonizing our generation fleet through investments in renewables and natural gas, has made significant advancements in reducing its GHG emissions



Emera recently published its Sustainability Report which highlights our progress on Environmental, Social and Governance initiatives

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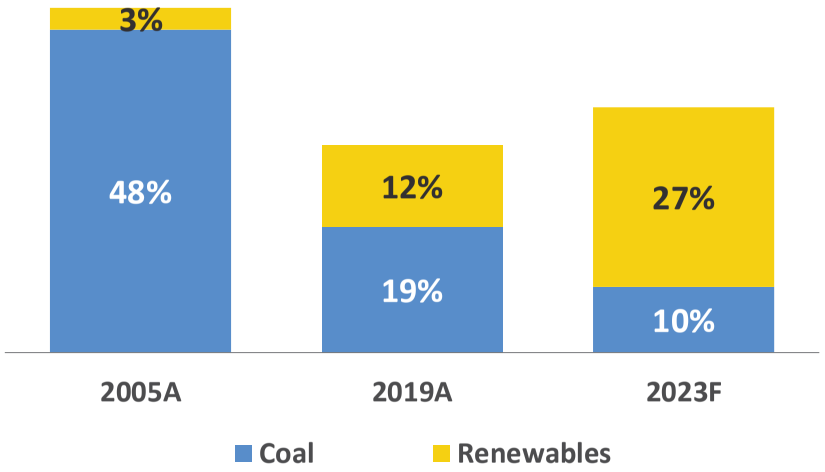
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Emera's Decarbonization Strategy in Action

The integration of renewables and natural gas has significantly transformed Emera's generation fleet and our committed capital projects will further advance our decarbonization strategy

Nova Scotia Power and Tampa Electric[1]

Coal and Renewables as a % of total GWh Generation

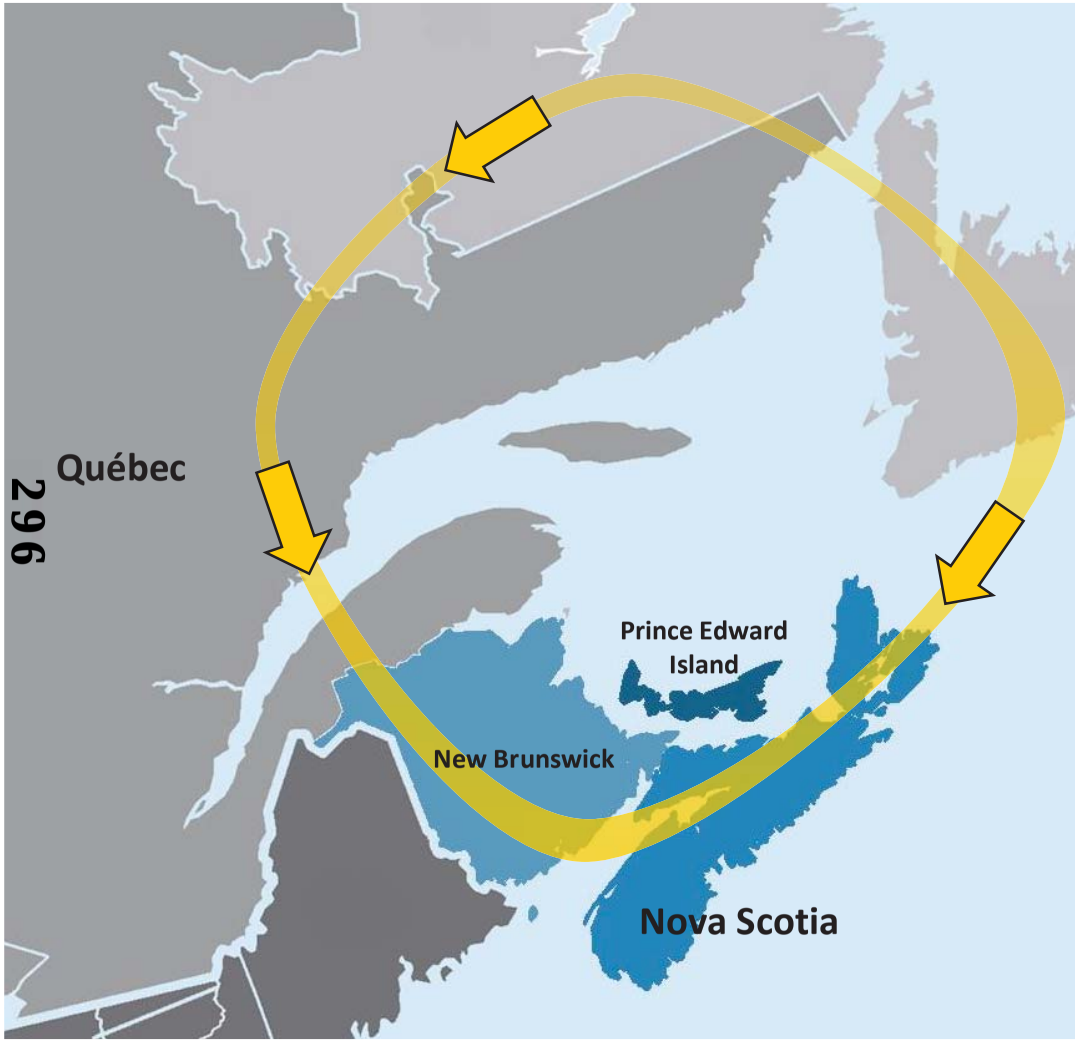


- ~80% reduction in coal generation by 2023
- Renewables to increase from 3% in 2005 to 27% in 2023
- Natural gas, a transition fuel, to increase from 23% in 2005 to 59% in 2023

[1] Represents the total GWh for Tampa Electric and Nova Scotia Power

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Atlantic Loop Project



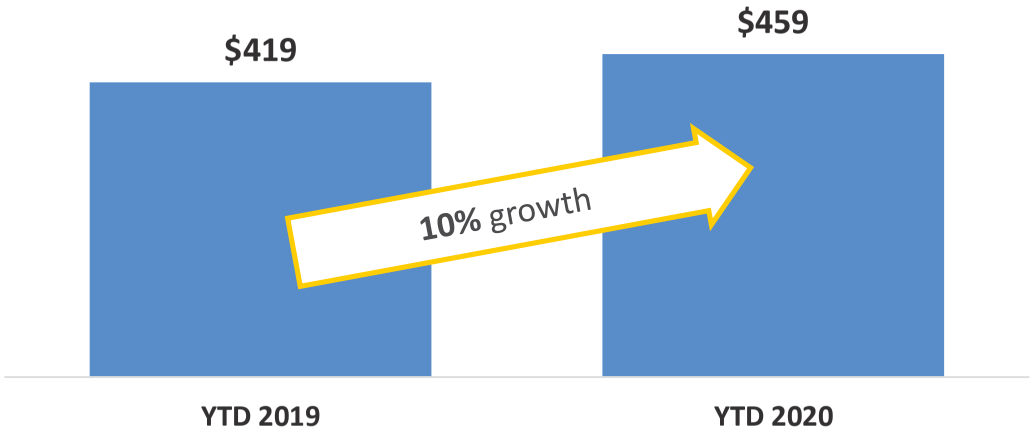
Engaging with electricity sector partners and governments to collaborate and pursue an accelerated transition to cleaner energy through the development of new large-scale transmission that will enable the movement of clean energy and firm capacity through the Atlantic region.

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Financial Results

Greg Blunden
CFO

Strong YTD Performance by Regulated Businesses[1]



Emera's earnings quality continues to improve as regulated earnings grow

[1] Regulated and corporate adjusted earnings in millions of CAD (excluding Emera Maine and the impacts of preferred dividend timing in 2020)

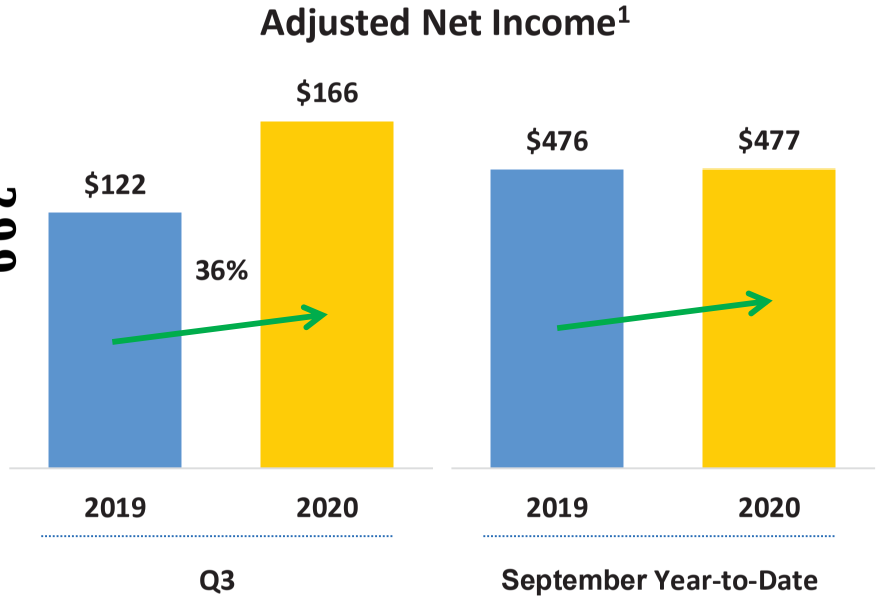
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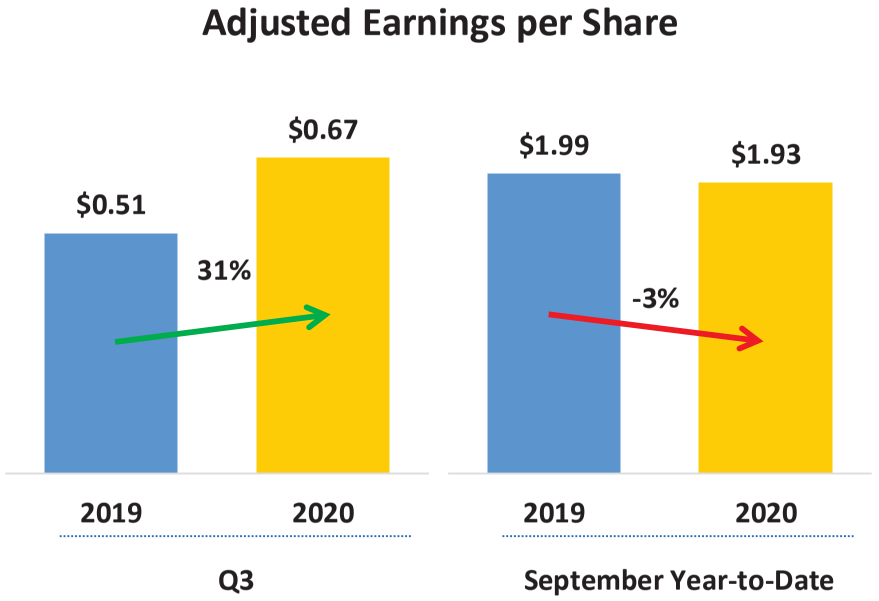
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Adjusted Earnings and Adjusted EPS





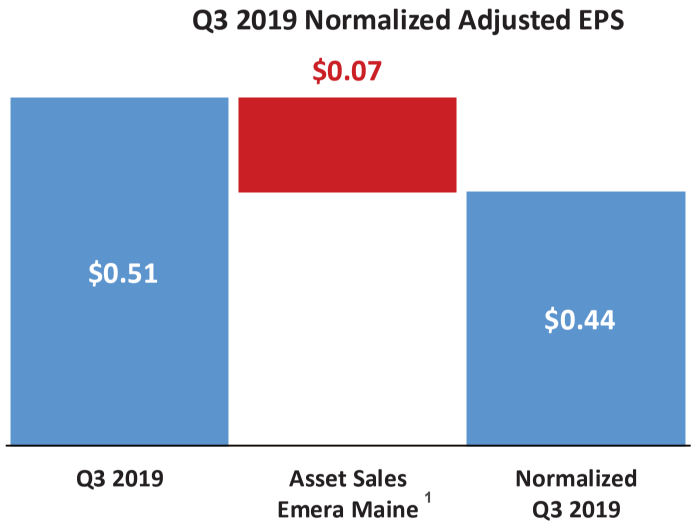
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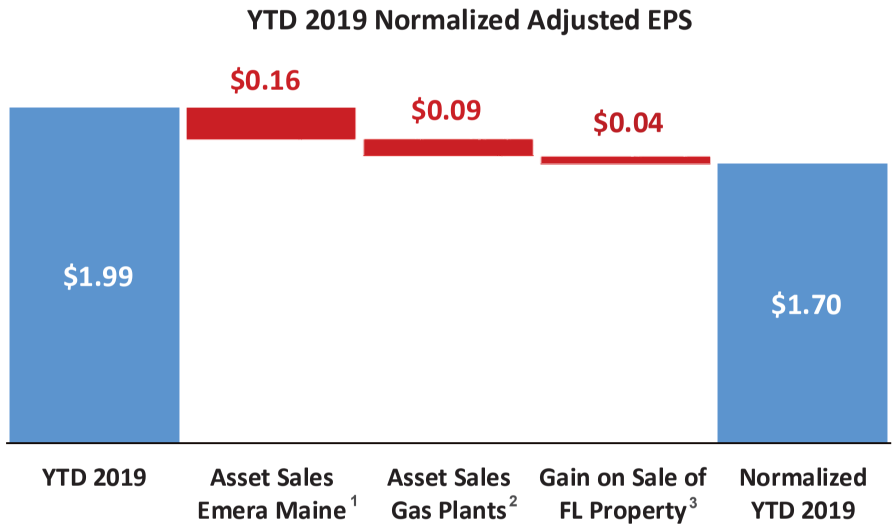
[1] In millions of dollars

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Normalizing Adjusted EPS for Asset Sales





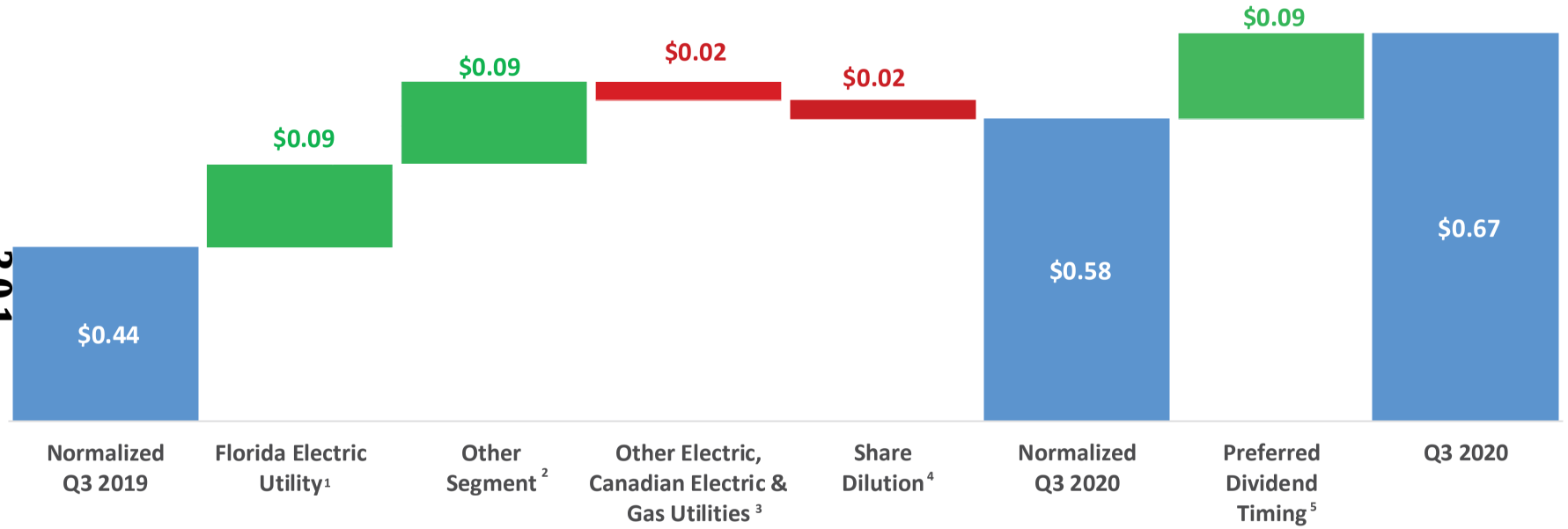
[1] Emera Maine was sold in March 2020
[2] Emera unregulated gas plants were sold in Q1 2019
[3] Emera recognized a $10 million gain on the sale of a property in Florida in Q1 2019

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Key Drivers of Q3 2020 Adjusted EPS



[1] Higher earnings due to increased base revenues (favourable weather and customer growth), higher AFUDC as a result of the Big Bend modernization and solar projects, and lower depreciation and amortization expense as a result of a regulatory settlement

[2] Corporate costs were lower in the current year ($+0.08) from lower interest costs and Q3 2019 included costs related to Hurricane Dorian. Emera Energy experienced improved earnings in 2020 due to lower fixed commitments for gas transportation and storage assets ($+0.01)

[3] Decreased earnings from Other Electric Utilities excluding Emera Maine (-$0.01) and the Gas Utilities (-$0.02), partially offset by increased earnings in Canadian Electric Utilities (+$0.01)

[4] Reflects increase in the number of common shares issued and outstanding

[5] Timing of preferred share dividend declaration in Q3 2020 as compared to Q3 2019

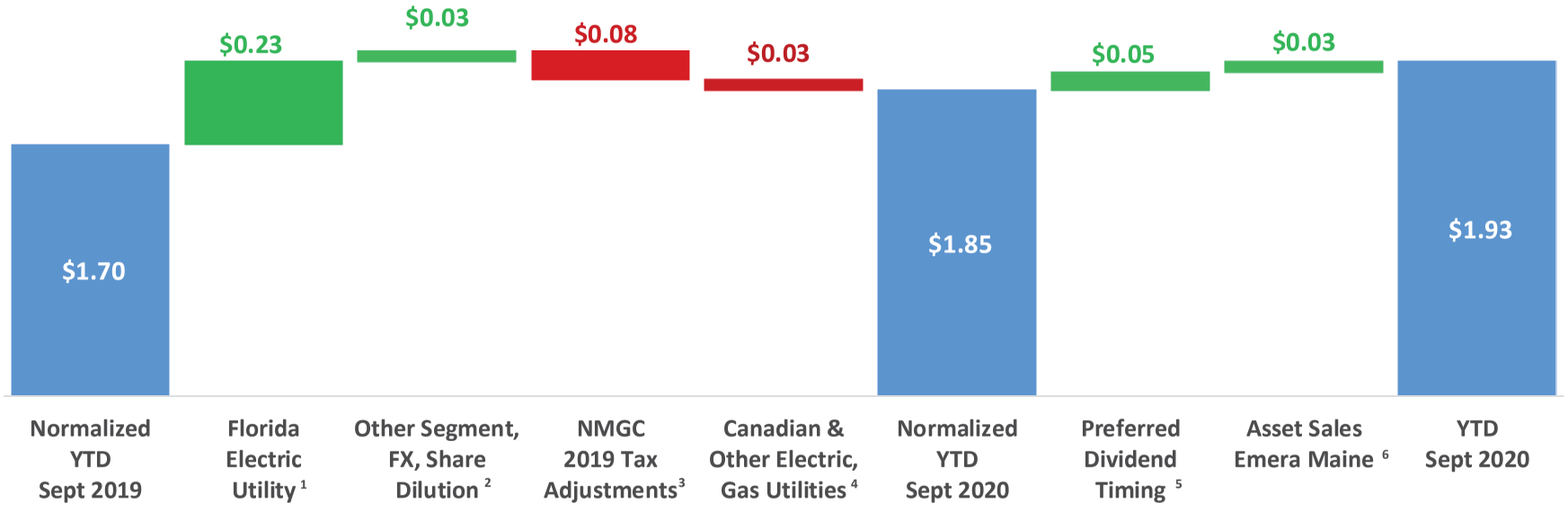
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Key Drivers of Year-to-Date Adjusted EPS



[1] Higher earnings due to increased base revenues (favourable weather and customer growth), higher AFUDC as a result of the Big Bend modernization and solar projects, and lower depreciation and amortization expense as a result of a regulatory settlement

[2] Includes the higher earnings at Emera Energy (+$0.02), other items (+$0.04), FX ($+0.03), less share dilution (-$0.06)

[3] 2019 included the one-time recognition of tax benefits related to NOL carryforwards and tax reform benefits in NMGC (~$19m)

[4] Other Electric Utilities, excluding Emera Maine, had lower earnings (-$0.02) in 2020 from COVID-19 and Hurricane Dorian, partially offset by the recognition of deferred taxes at BLPC. Canadian Electric Utilities ($-0.03) had lower earnings from increased income tax expense and decreased sales volumes partially offset by higher equity earnings. Gas Utilities were slightly positive (+$0.02) when excluding 2019 one-time adjustments

[5] Timing of preferred dividend declaration for the year-to-date 2020 as compared to 2019

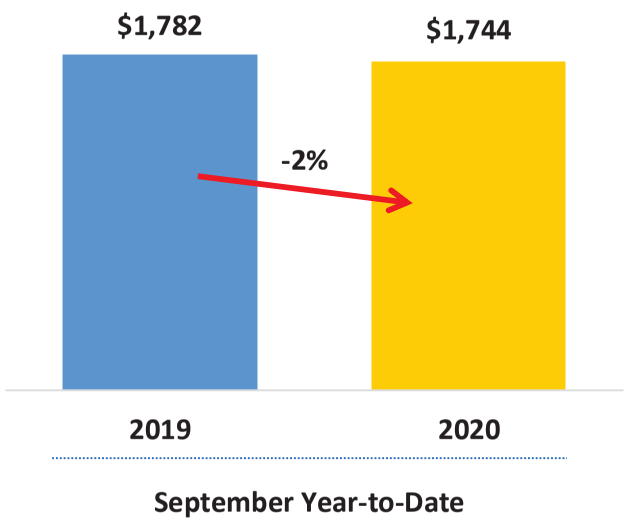
[6] Emera Maine earnings for Q1 2020, sold in March 2020

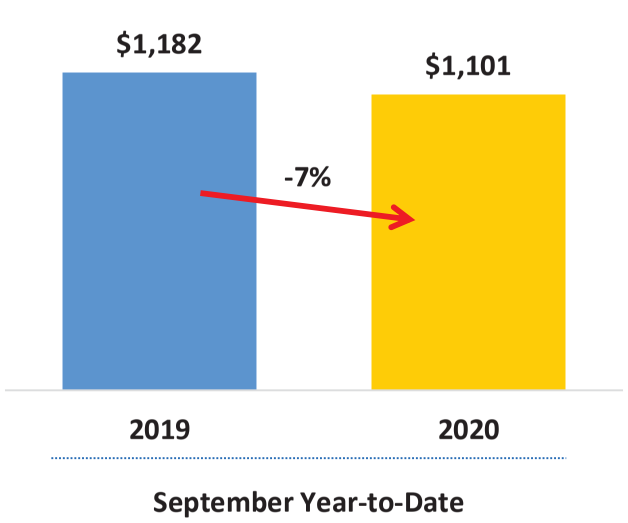
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Adjusted EBITDA and Operating Cash Flow





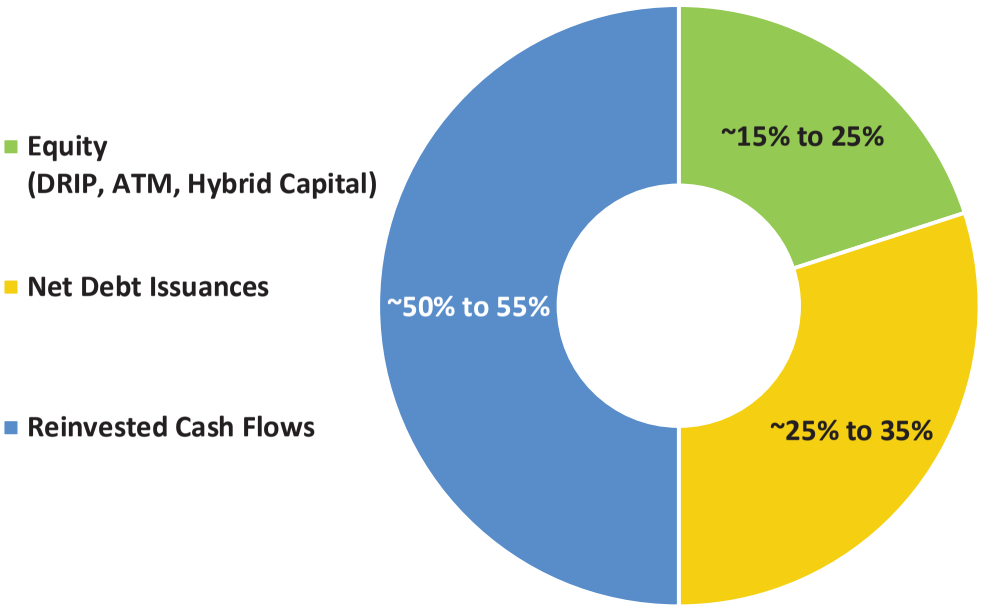
[1] Refer to the Q3 2020 Emera financial statements and MD&A for a reconciliation of EBITDA to reported net income

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Target Sources of Funding 2021 to 2023



- Cash flow from operations provides significant funding
- Funding plan achieves targeted capital structure and credit metrics
- Maintains regulated capital structures through the issuance of Opco debt
- Equity requirements to be filled with DRIP, ATM and hybrid capital

[1] Net debt issuances include Opco debt issuances net of Holdco repayments
[2] Reinvested cash flow is net of expected common and preferred dividend requirements

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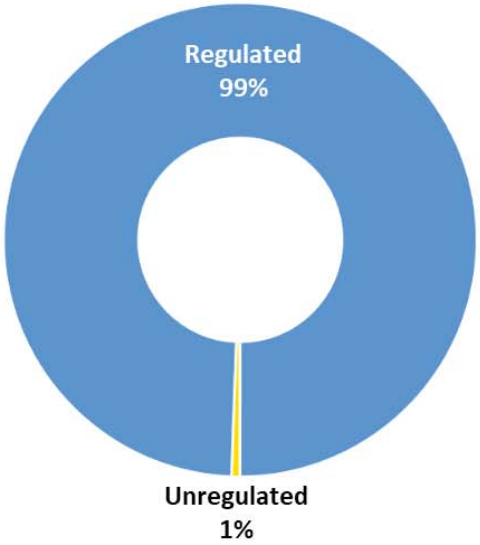
Upcoming Investor Events
Expected Q4/20 Results & Conference Call
Tuesday, February 16, 2021
Emera
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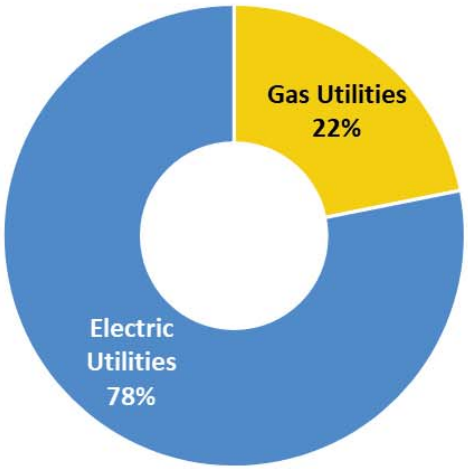
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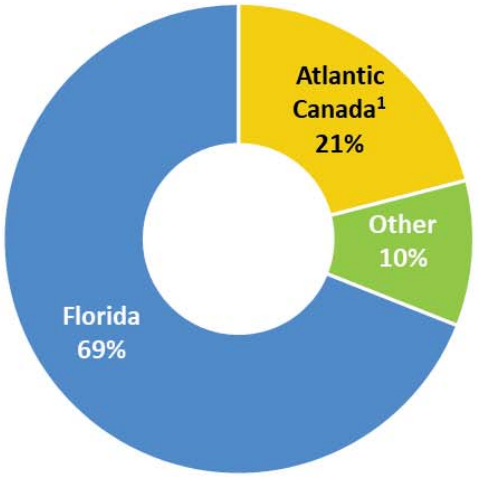


Investing in our Regulated Utilities

2021-2023 Capital Program







[1] Atlantic Canada includes Nova Scotia Power, NSP Maritime Link and the Labrador Island Link

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Investing in Cleaner, More Reliable Energy

Capital Projects (2021 to 2023)	Total
Infrastructure Upgrades, Grid Modernization, etc.	$1,360
Solar Investments – Tampa Electric	810
Storm Hardening – Tampa Electric	540
Reliability Projects & CIBS/PP[2] Investments – PGS & NMGC	520
Big Bend Modernization – Tampa Electric	360
RNG, CNG & LNG Projects	340
Hydro Renewal – Nova Scotia Power	290
Transmission Investment – Labrador Island Link	240
Smart Meters & LED Streetlights	190
Total	**4,650**
% of Baseline Capital Program	**~60%**

[1] In millions of Canadian dollars. US dollar denominated capex is translated at a forecasted average USD/CAD exchange rate of 1.33
[2] Cast iron/bare steel and problematic plastic

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Capital Forecast by Affiliate

Capital Forecast (CAD millions)		2021F	2022F	2023F	Total
Tampa Electric	$	1,300	1,370	1,360	4,030
Peoples Gas		400	390	350	1,140
Seacoast		30	60	40	130
New Mexico Gas		140	140	140	420
Nova Scotia Power		410	360	360	1,130
Emera Caribbean		60	110	100	270
Emera Newfoundland		-	240	-	240
Other		10	20	10	40
Subtotal - Baseline Forecast	**$**	**2,350**	**2,690**	**2,360**	**7,400**
Add: Opportunities Under Development		170	440	590	1,200
Capital Forecast (CAD millions)	**$**	**2,520**	**3,130**	**2,950**	**8,600**

[1] US dollar denominated capex is translated at a forecasted average USD/CAD exchange rate of 1.33 in 2021 - 2023

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Rate Base Forecast by Affiliate

Rate Base (CAD millions)[1]		2019A	2020F	2021F	2022F	2023F	2019-2023 CAGR
Tampa Electric[2]	$	9,225	10,335	11,200	12,025	12,815	8.6%
Peoples Gas[2]		1,450	1,810	2,225	2,535	2,810	18.0%
Seacoast[3]		85	185	205	245	270	33.5%
New Mexico Gas Company		775	845	990	1,005	1,050	7.9%
Nova Scotia Power		4,100	4,275	4,495	4,655	4,820	4.1%
Emera Caribbean		950	915	970	985	990	1.0%
Maritime Link		1,825	1,820	1,800	1,750	1,695	-1.8%
Labrador Island Link[4]		550	600	650	875	875	12.3%
Subtotal - Baseline Forecast	**$**	**18,960**	**20,785**	**22,535**	**24,075**	**25,325**	**7.5%**
Add: Opportunities Under Development		-	-	90	390	910	
Total	**$**	**18,960**	**20,785**	**22,625**	**24,465**	**26,235**	**8.5%**

[1] Average rate base; US dollar denominated rate base is translated at a forecasted average USD/CAD exchange rate of 1.33 in 2020-2023
[2] Capital structures that support the rate base include deferred tax liabilities (DTL), a zero cost-of-capital component of the capital structure in Florida; 2019 capital structures included DTLs of $1,200 million at Tampa Electric and $200 million at Peoples Gas
[3] Reflects the capital asset values of the regulated pipeline investments
[4] Reflects Emera's equity investment in the project

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Emera Energy Quarterly Adjusted Earnings Contribution

Millions of Canadian dollars		Q1/18	Q2/18	Q3/18	Q4/18	Q1/19	Q2/19	Q3/19	Q4/19	Q1/20	Q2/20	Q3/20
Marketing and Trading	$	37	(5)	-	21	30	(20)	(19)	14	19	(11)	(11)
NEGG[1]		10	7	19	19	18	(2)	1	-	-	-	-
Maritimes Canada		4	(5)	(6)	(4)	0	(1)	-	(1)	(2)	-	1
Bear Swamp		4	5	6	8	4	4	4	4	4	4	(2)
Total (excl. MTM and loss on sale)	**$**	**55**	**2**	**19**	**44**	**52**	**(19)**	**(14)**	**17**	**21**	**(7)**	**(12)**
Net (loss)/gain on sale (recorded in Corporate)		-	-	-	-	(2)	(1)	-	-	-	-	-

Millions of CAD dollars		2012	2013	2014	2015	2016	2017	2018	2019
Marketing and Trading Earnings	$	10	31	68	44	25	19	53	5
Average (2012 to 2019)	$	32							
Average (2012 to 2019) excluding outliers	$	26							

[1] Q1/18 to Q1/19, inclusive, includes approximately $6 million per quarter of intercompany interest expense paid to Emera Corporate, where it was recorded as intercompany interest revenue. Emera Corporate financed the original acquisition off its balance sheet. No permanent debt financing was transferred with the sale of the gas plants.

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Non-GAAP Reconciliation

For the millions of Canadian dollars (except per share amounts)		Three months ended September 30		Nine months ended September 30	
		2020	2019	**2020**	2019
Net income (loss) attributable to common shareholders	**$**	**84**	55	**665**	470
Gain (loss) on sale and impairment charges, net of taxes		**-**	-	**283**	-
After-tax mark-to-market gain (loss)		**(82)**	(67)	**(95)**	(6)
Adjusted net income attributable to common shareholders	**$**	**166**	122	**477**	476
Weighted average shares		**248**	241	**247**	239
Earnings per common share – basic	**$**	**0.34**	0.23	**2.70**	1.97
Adjusted earnings per common share – basic	**$**	**0.67**	0.51	**1.93**	1.99

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Fourth Quarter 2020

February 16, 2021

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Forward Looking Information and Non-GAAP Measures

Forward-Looking Information

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

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Non-GAAP Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. Refer to the Non-GAAP Financial Measures section of our MD&A for further discussion of these items.

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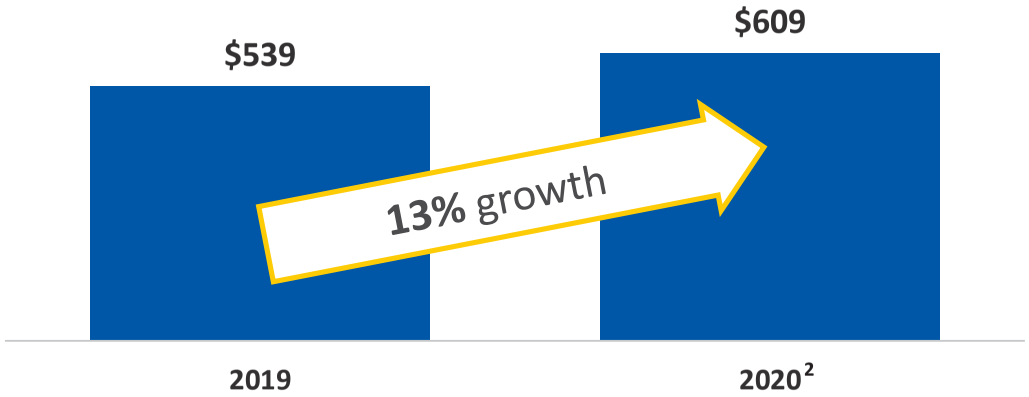
Staff Hearing Exhibits 20220048-EI - 20220048-EI

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220048-EI
OPC'S SECOND REQUEST FOR
PRODUCTION OF DOCUMENTS
FILED: MAY 18, 2022

Business Update

Scott Balfour
President and CEO

Strong Regulated Earnings Growth



Emera's regulated portfolio is driving steady and predictable EPS growth

[1] Regulated earnings, net of corporate costs and excluding Emera Maine, in millions of CAD; reconciliation to adjusted net income included in the appendix
[2] Excludes TECO Guatemala legal award of $36 million in Q4 2020

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2020 Accomplishments

- ✓ **Donated over $6 million** to our communities
- ✓ **Completed the sale of Emera Maine**; proceeds used to retire debt and fund growth
- ✓ **Invested $2.7 billion, our largest ever annual capital program,** maintaining budget and schedule of all major capital projects
- ✓ **Finished construction first 600MW of solar in Tampa**; announced and began construction of second 600MW
- ✓ **Negotiated settlement agreements** at Peoples Gas and New Mexico Gas
- ✓ **Issued fourth Sustainability Update**, incorporating the SASB and TCFD frameworks



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Staff Hearing Exhibits 20220048-EI - 20220048-EI 00021

Our Climate Commitment



How we'll get there

We'll seek to achieve these goals and realize our net-zero vision by adopting emerging technologies and working constructively with policymakers, regulators, partners, investors, and our communities. All while staying focused on enhancing reliability and never losing sight of affordability for our customers.

Investing $4.7B+ in cleaner and reliable energy (2021 - 2023)

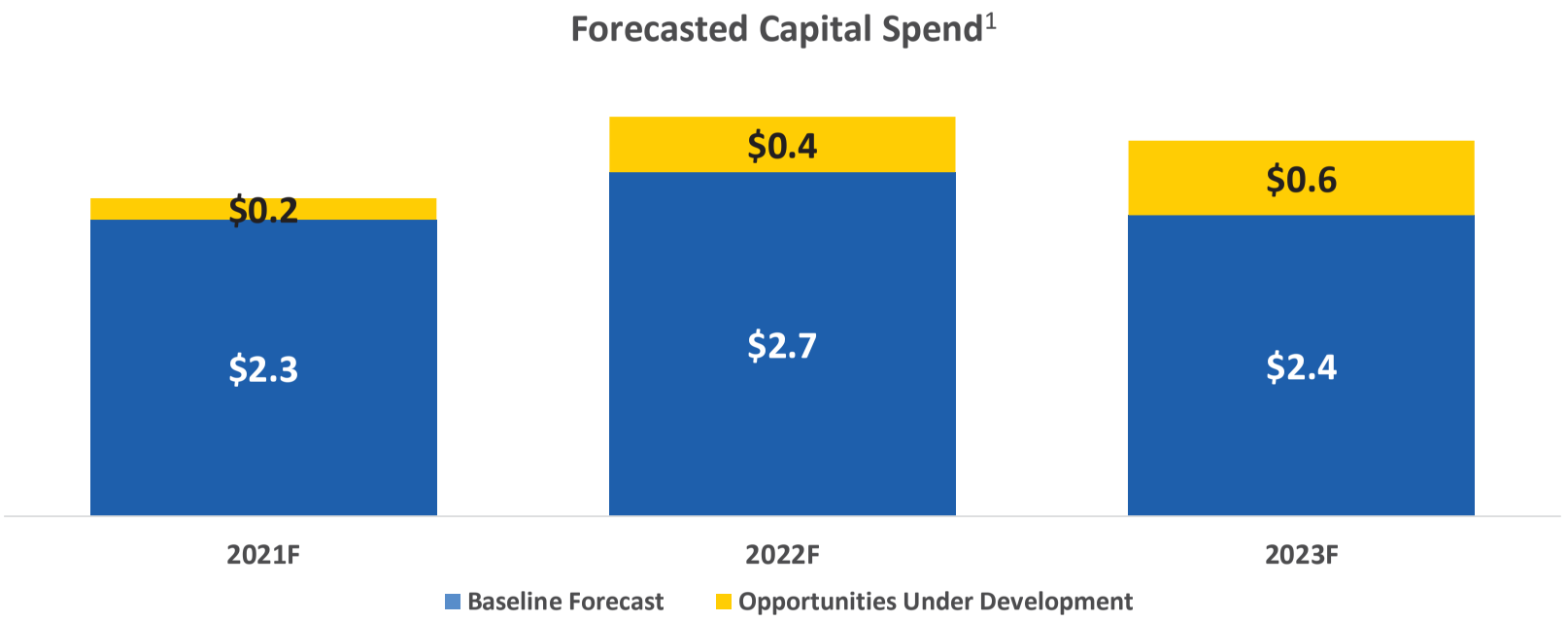
Coal Reduction | Renewables & Low-Carbon Energy | Transmission | Customer Solutions
Batteries | Smart Grids | Microgrids | EVs | Emerging Technologies

*Measurements as of December 31, 2020.
CO_2 emission measurements are compared to 2005 levels.
Reductions in coal use are measured as a percentage of GWh generation

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Investing Between $7.4B to $8.6B in Rate Base

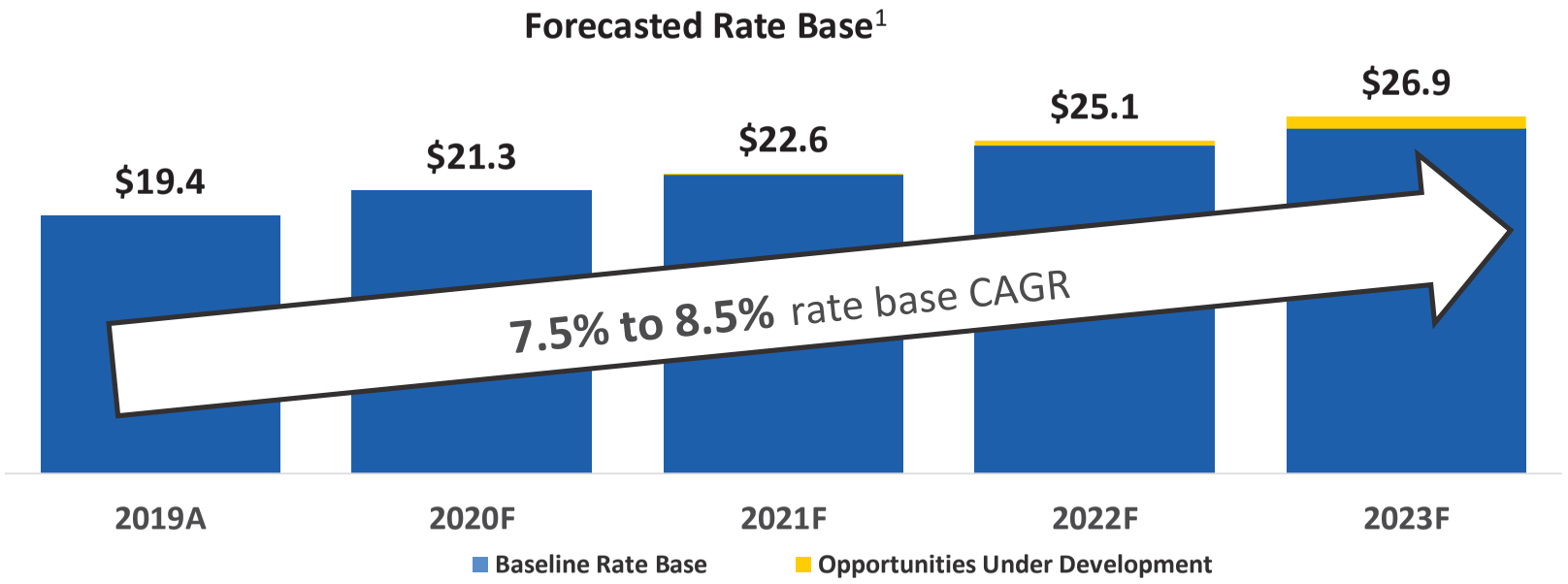


[1] In billions of Canadian dollars. US dollar denominated capex is translated at a forecasted average USD/CAD exchange rate of 1.28 in 2021 and 1.33 in 2022-2023. Capital spend forecast by affiliate can be found in the appendix.

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Capital Program Drives Future Rate Base Growth



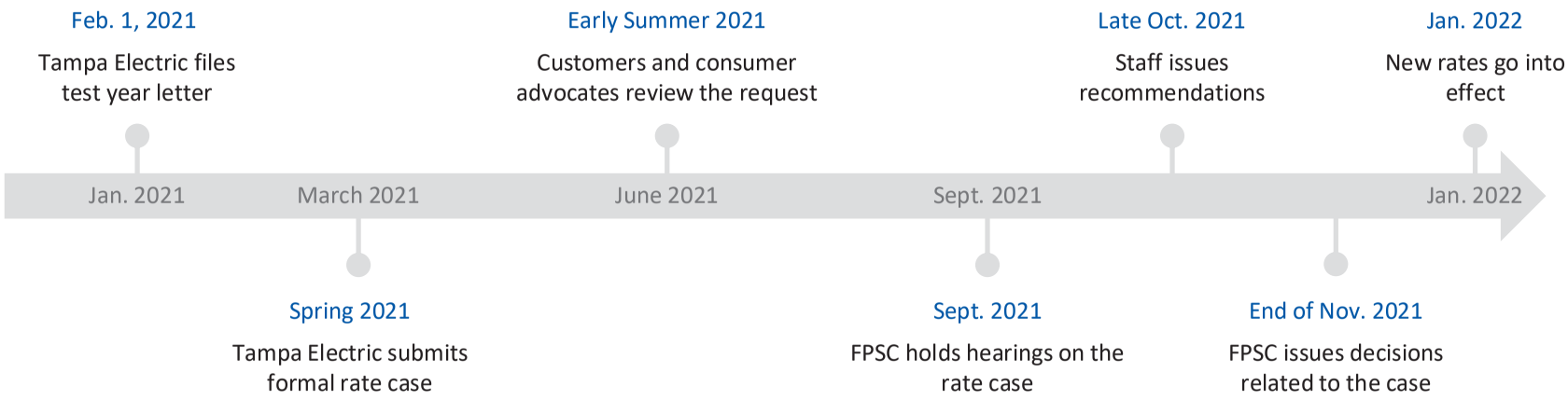
[1] 2019 actuals exclude Emera Maine. Average total rate base in billions of Canadian dollars. U.S. dollar denominated rate base is translated at a forecasted exchange rate of 1.28 in 2021 and 1.33 in 2022-2023. Details by affiliate can be found in the appendix.

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Tampa Electric Rate Case



Typical bill will only be 4% higher than a decade ago; 20% lower when adjusted for inflation

Rates will continue to be among the lowest in Florida and well below national average

2022

New rates will be in effect in January 2022

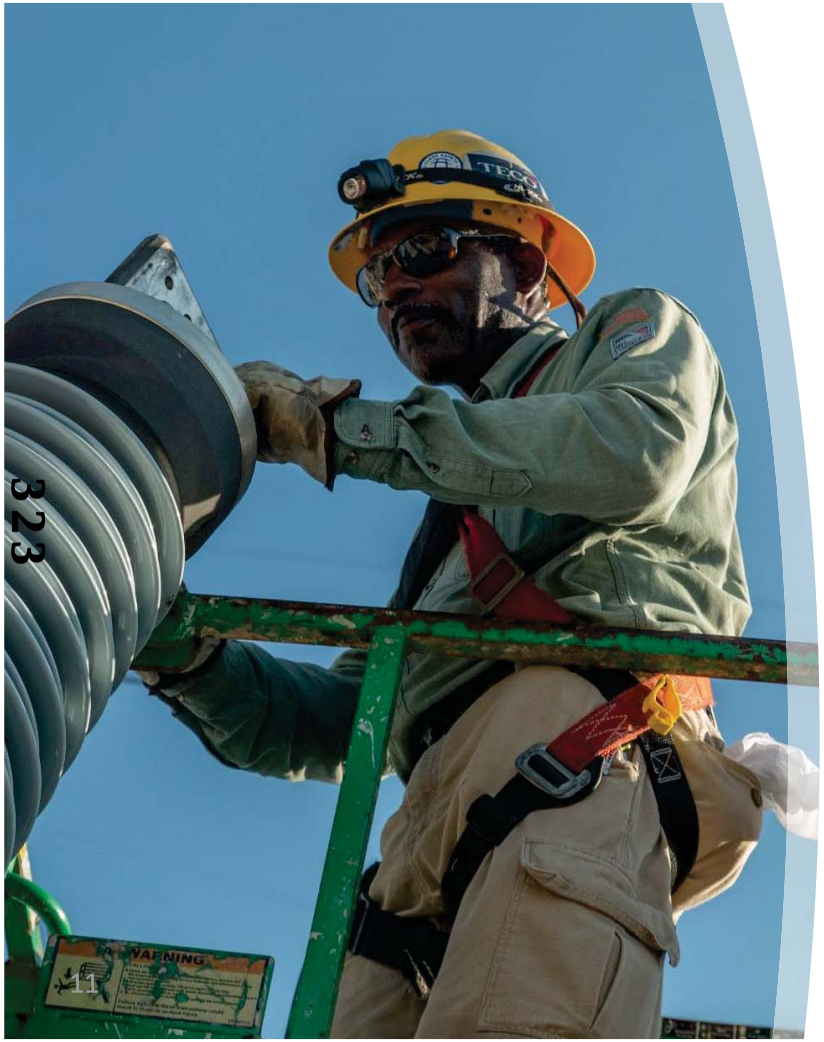
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Financial Results

Greg Blunden
CFO



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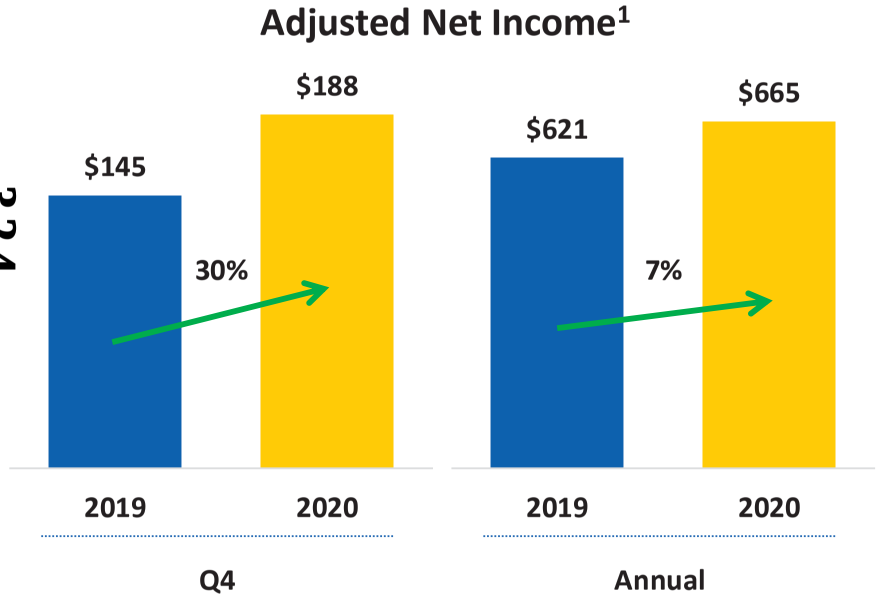
Delivering for Shareholders

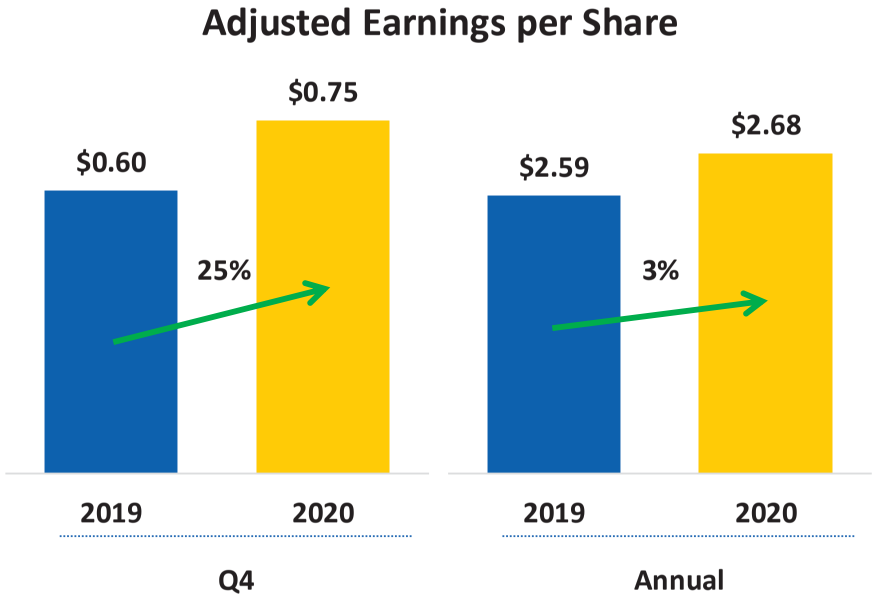
- ✓ **Grew our regulated earnings by 13%,** including a 17% growth in our Florida utilities
- ✓ **Increased our common share dividend by 4%,** providing investors with a predictable and sustainable income stream
- ✓ **Improved future earnings and cash flow quality** with new base rates at PGS and New Mexico Gas and an increase in ENL cash flow in 2021 and anticipated new base rates at Tampa Electric in 2022
- ✓ **Strengthened our balance sheet** by achieving our target capital structure and retiring holding company debt

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Reported Adjusted Results





[1] In millions of Canadian dollars

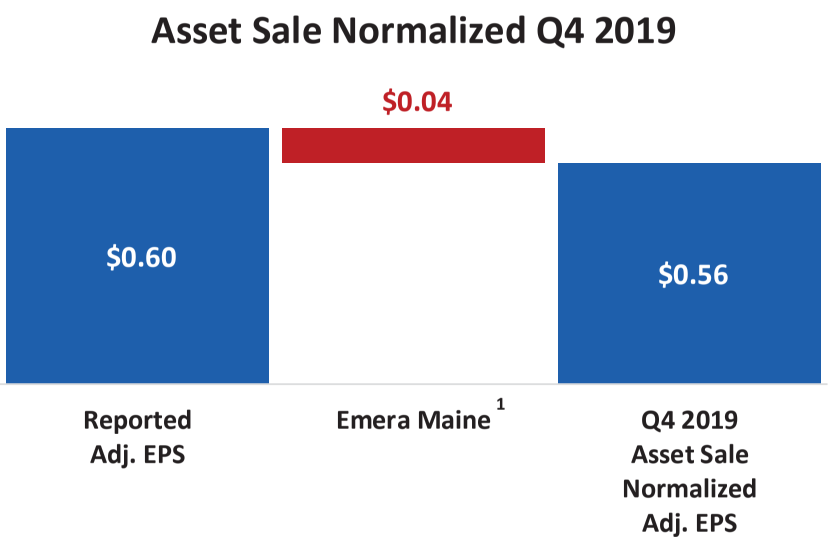
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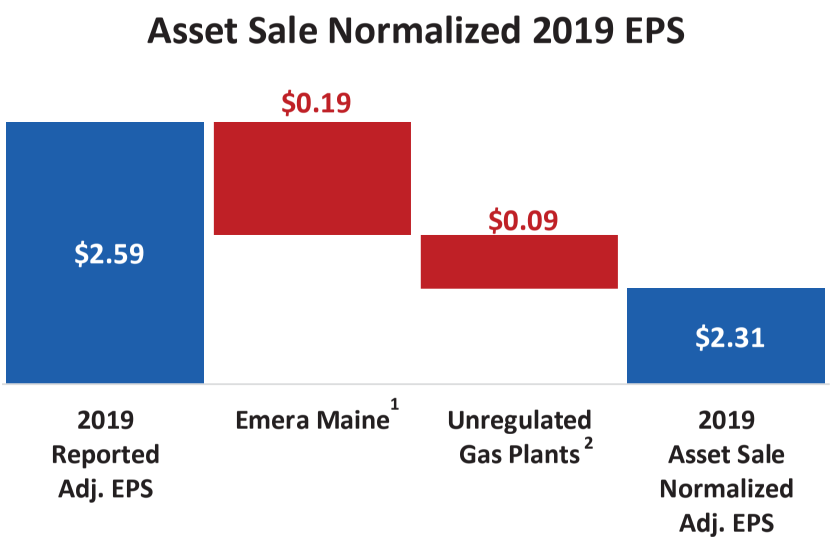
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Normalizing Adjusted EPS for Asset Sales





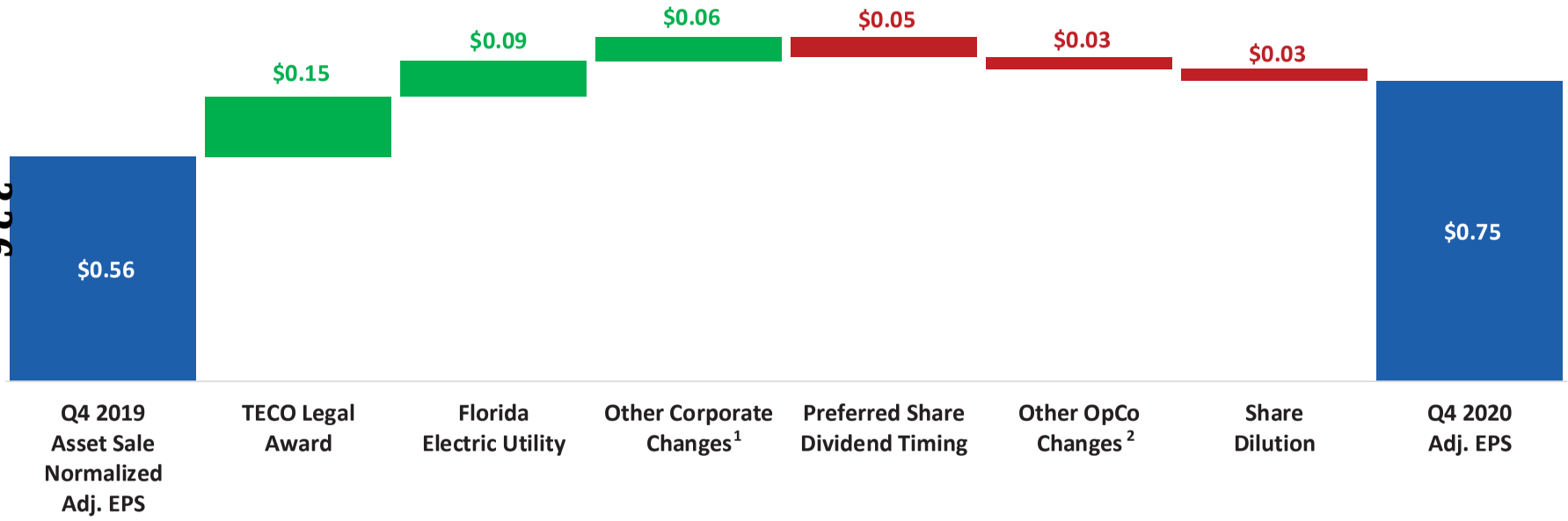
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[1] Operating earnings contribution; sale of Emera Maine was completed in March 2020
[2] Operating earnings contributions; sales of NEGG and Bayside unregulated gas plants were completed in Q1 2019

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Key Drivers of Q4 2020 Adjusted EPS Growth



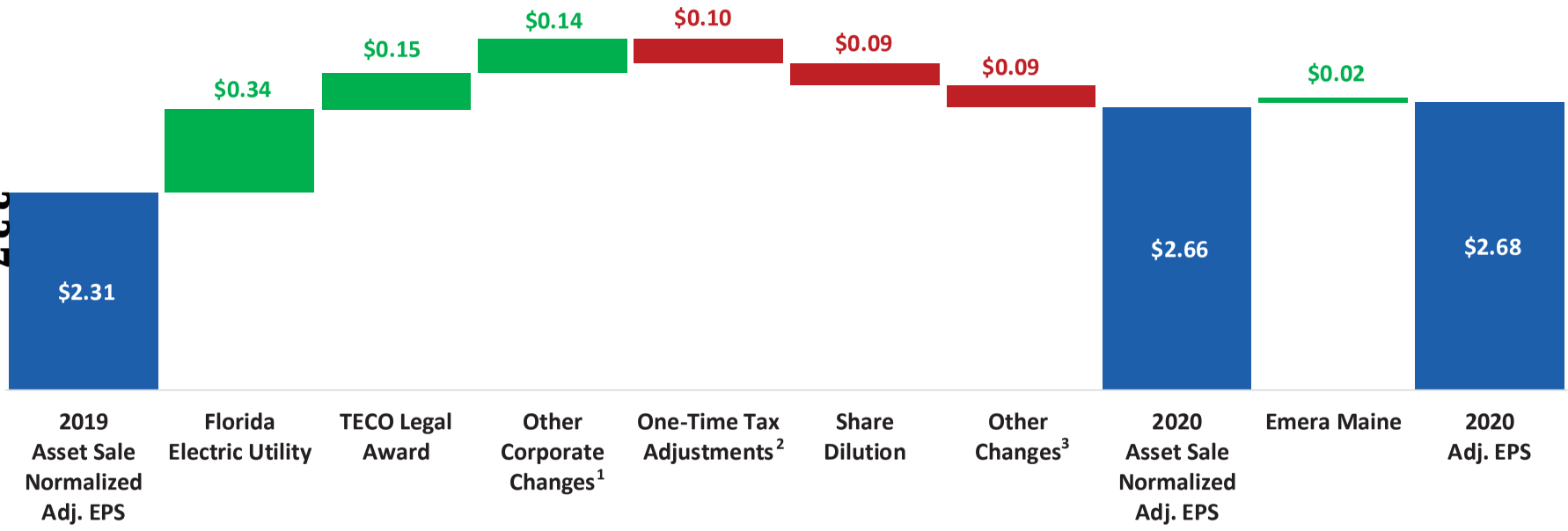
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[1] Includes corporate interest expense savings (+$0.04) and savings from one-time Hurricane Dorian costs in 2019 ($0.02)
[2] Includes changes in Other Electric Utilities (+$0.01), Gas Utilities and Infrastructure (-$0.03) and Emera Energy (-$0.01)

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Key Drivers of Annual Adjusted EPS Growth

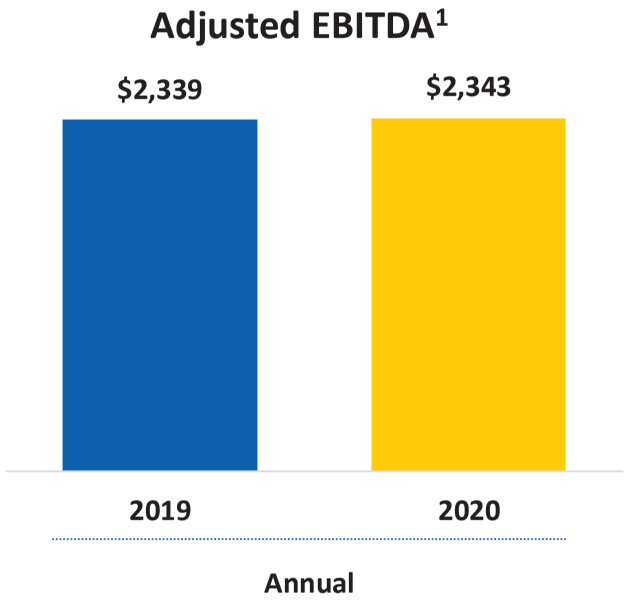


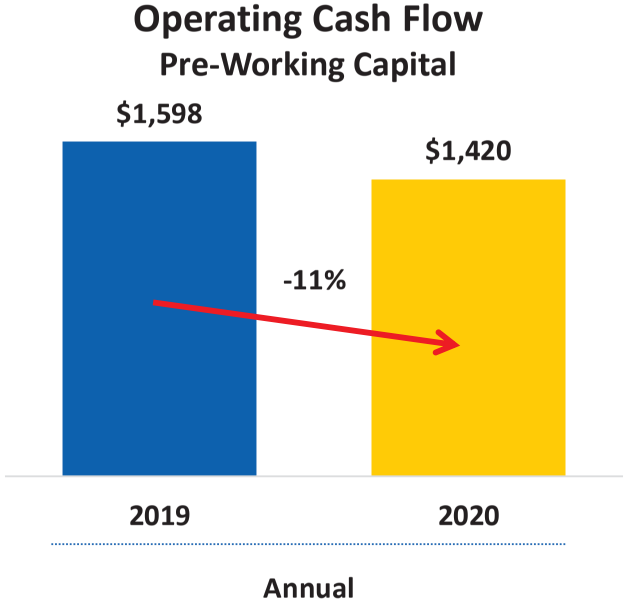
[1] Includes corporate interest expense savings (+$0.13), savings from one-time Hurricane Dorian costs in 2019 (+$0.06) and gain on sale of Florida property (-$0.04)
[2] Includes adjustment in New Mexico Gas (-$0.08) recorded in 2019 and adjustments in Corporate (-$0.06) and Barbados Light & Power (+$0.04) recorded in 2020
[3] Includes Canadian Electric Utilities (-$0.03), other changes in Emera Caribbean (-$0.05) and other changes in Gas Utilities and Infrastructure (-$0.01)

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Adjusted EBITDA and Operating Cash Flow





[1] Refer to the Q4 2020 Emera financial statements and MD&A for a reconciliation of EBITDA to reported net income

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Continuing to Execute on Credit Objectives

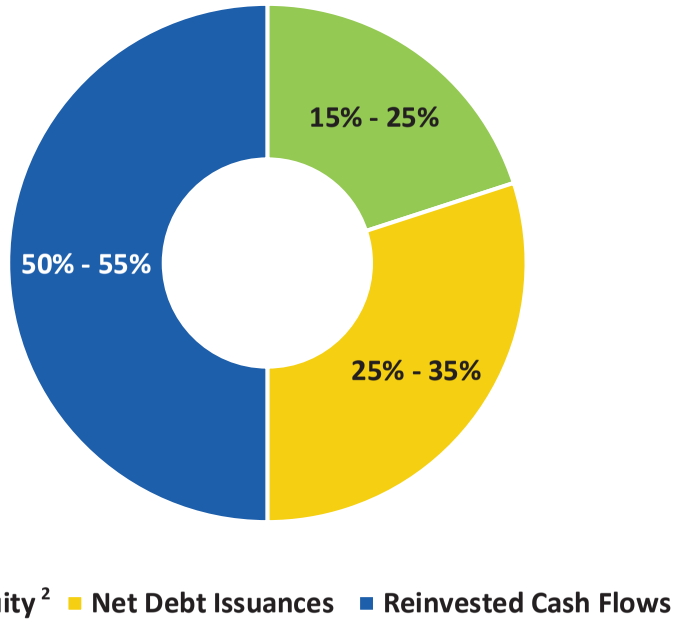
Emera Credit Objectives

1. Maintain target capital structure
2. Sustained cash flow-to-debt metrics > 12%
3. Sustained holdco debt-to-total debt < 40%

Emera Corporate Credit Ratings

Moody's	S&P	Fitch
Baa3 (Stable)	BBB- [1] (Stable)	BBB (Stable)

2021-2023 Target Sources of Funding



Emera

[1] Issue rating; issuer rating of BBB (stable)
[2] Includes DRIP, ATM and hybrid capital

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Emera
Upcoming Investor Events
Q1/21 Results & Analyst Call
Wednesday, May 12, 2021
Annual General Meeting
Thursday, May 20, 2021
Q2/21 Results & Analyst Call
Wednesday, August 11, 2021


Appendix
Emera
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Capital Forecast by Affiliate

Capital Forecast (CAD millions)[1]		2021F	2022F	2023F	Total
Tampa Electric	$	1,360	1,370	1,360	4,090
Peoples Gas		380	390	350	1,120
Seacoast		10	80	40	130
New Mexico Gas		130	140	140	410
Nova Scotia Power		370	380	380	1,130
Emera Caribbean		70	100	100	270
Emera Newfoundland		15	240	-	255
Other		10	20	10	40
Subtotal - Baseline Forecast	**$**	**2,345**	**2,720**	**2,380**	**7,445**
Opportunities Under Development		170	440	590	1,200
Capital Forecast (CAD millions)	**$**	**2,515**	**3,160**	**2,970**	**8,645**

[1] In billions of Canadian dollars. US dollar denominated capex is translated at a forecasted average USD/CAD exchange rate of 1.28 in 2021 and 1.33 in 2022-2023.

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Rate Base Forecast by Affiliate

Rate Base Forecast (CAD millions)[1]		2019A	2020A	2021F	2022F	2023F	2019-2023 CAGR
Tampa Electric[2]	$	9,225	10,400	10,895	12,215	13,015	9.0%
Peoples Gas[2]		1,450	1,760	2,095	2,490	2,765	17.5%
Seacoast[3]		85	185	185	235	270	33.5%
Emera New Brunswick[3]		460	450	445	435	430	-1.7%
New Mexico Gas		775	855	960	1,015	1,060	8.1%
Nova Scotia Power		4,100	4,225	4,430	4,580	4,770	3.9%
Emera Caribbean		950	970	985	1,035	1,040	2.3%
Maritime Link		1,825	1,840	1,825	1,785	1,725	-1.4%
Labrador Island Link[4]		550	605	655	880	880	12.5%
Subtotal - Baseline Forecast	**$**	**19,420**	**21,290**	**22,475**	**24,670**	**25,955**	**7.5%**
Opportunities Under Development		-	-	90	390	910	
Rate Base Forecast (CAD millions)		**19,420**	**21,290**	**22,565**	**25,060**	**26,865**	**8.5%**

[1] Average rate base; US dollar denominated rate base is translated at a forecasted average USD/CAD exchange rate of 1.28 in 2021 and 1.33 in 2022-2023
[2] Capital structures that support the rate base include deferred tax liabilities (DTL), a zero cost-of-capital component of the capital structure in Florida; 2019 capital structures included DTLs of $1,200 million at Tampa Electric and $200 million at Peoples Gas
[3] Reflects the capital asset values of the regulated pipeline investments
[4] Reflects Emera's equity investment in the project

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Emera Energy Quarterly Adjusted Earnings Contribution

Millions of Canadian dollars		Q1/19	Q2/19	Q3/19	Q4/19	Q1/20	Q2/20	Q3/20	Q4/20
Marketing and Trading	$	30	(20)	(19)	14	19	(11)	(11)	11
NEGG[1]		18	(2)	1	-	-	-	-	-
Maritimes Canada		0	(1)	-	(1)	(2)	-	1	0
Bear Swamp		4	4	4	4	4	4	(2)	4
Total (excl. MTM and loss on sale)	**$**	**52**	**(19)**	**(14)**	**17**	**21**	**(7)**	**(12)**	**15**
Net (loss)/gain on sale (recorded in Corporate)		(2)	(1)	-	-	-	-	-	-

Millions of CAD dollars		2013	2014	2015	2016	2017	2018	2019	2020
Marketing and Trading Earnings	$	31	68	44	22	15	53	5	8
Average (2013 to 2020)	**$**	**31**							
Average (2013 to 2020) ex. outliers[2]	**$**	**39**							

[1] Q1/19, inclusive, includes approximately $6 million per quarter of intercompany interest expense paid to Emera Corporate, where it was recorded as intercompany interest revenue. Emera Corporate financed the original acquisition off its balance sheet. No permanent debt financing was transferred with the sale of the gas plants

[2] Excluding 2019 and 2020

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Non-GAAP Reconciliation

For the millions of Canadian dollars (except per share amounts)		Three months ended December 31		Year ended December 31	
		2020	2019	**2020**	2019
Net income (loss) attributable to common shareholders	$	**273**	193	**938**	663
Gain (loss) on sale and impairment charges, net of taxes		**-**	-	**309**	-
Impairment charges, net of tax		**-**	(34)	**(26)**	(34)
After-tax mark-to-market gain (loss)		**85**	82	**(10)**	76
Adjusted net income attributable to common shareholders	$	**188**	145	**665**	621
Weighted average shares		**251.3**	242.9	**247.8**	239.9
Earnings per common share – basic	$	**1.09**	0.79	**3.78**	2.76
Adjusted earnings per common share – basic	$	**0.75**	0.60	**2.68**	2.59

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Regulated Earnings Growth

Regulated Earnings		**2020**	2019
Adjusted net income	**$**	**665**	621
Less:			
Emera Maine		**(5)**	(46)
Emera Energy		**(17)**	(37)
TECO Guatemala legal award		**(36)**	-
Other unregulated loss		**2**	1
Regulated earnings, net of corporate costs	**$**	**609**	539
Growth	**%**	**13**	

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First Quarter 2021
MAY 12, 2021
Emera

FORWARD LOOKING INFORMATION AND NON-GAAP MEASURES

Forward-Looking Information

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Scott
Balfour
President and CEO
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BUSINESS UPDATE
Emera

OFF TO A SOLID START IN 2021

Adjusted EPS[1]	Q1/21	Q1/20	Delta
Regulated and Corporate	$0.81	$0.71	+$0.10
Unregulated[2]	$0.15	$0.08	+$0.07
Consolidated	**$0.96**	**$0.79**	**+$0.17**

- \+ Continued strength in the regulated portfolio
- \+ Lower corporate costs
- \+ Improved marketing and trading earnings
- − Weather, stronger CAD and higher share count

Emera

[1] Adjusted net income and adjusted earnings per share are non-GAAP measures. See appendix for reconciliation to the nearest GAAP measure; [2] Unregulated earnings include Emera Energy, Emera Technologies and Other earnings in the Other segment

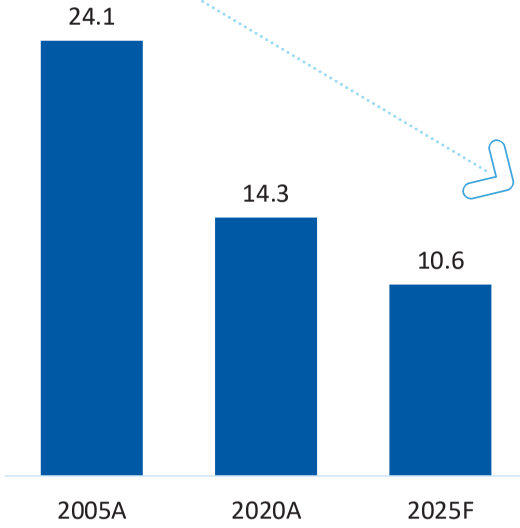


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CLEAR PATH TO OUR 2025 CO_2 GOAL

Successful execution of Emera's strategy, which includes a focus on decarbonizing our generation fleet through investments in renewables and lower carbon energy sources, will reduce CO_2 emission by 55% by 2025.

Tampa Electric and Nova Scotia Power CO_2 Emissions (in Mt)



55%
reduction in CO_2 emissions



Emera

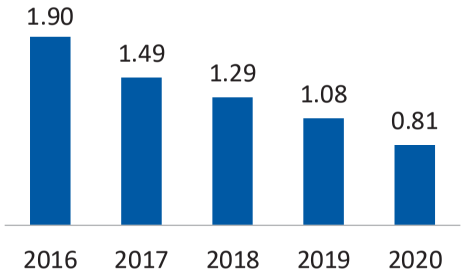
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JOURNEY TO WORLD CLASS SAFETY

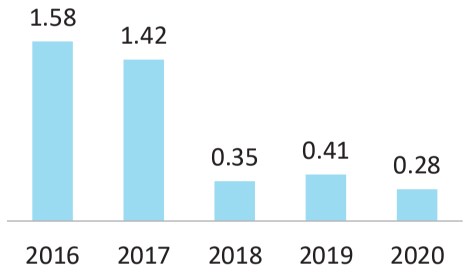
- **We are committed to an Emera where no one gets hurt.**
- We are fostering a “speak-up” culture, empowering every team member to be a safety leader.
- Our safety management program includes the following initiatives:
  - Proactive safety reporting
  - Personal safety plans
  - Field safety observations
  - Frequent safety communications
  - Emera-wide Safety Management System
- **We’re proud of our progress, but this work is never done.** We are relentlessly focused on keeping our customers, communities and each other safe.

Emera

OSHA[1] Injury Rate



Lost Time Injury Frequency Rate







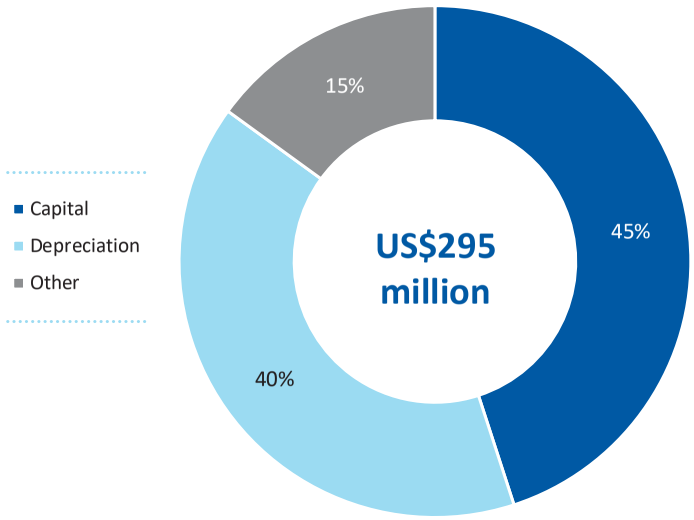


[1] Occupational Safety and Health Administration

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TAMPA ELECTRIC RATE CASE

2022 Base Revenue Ask



- Tampa Electric filed petition with the Florida Public Service Commission ("FPSC") on April 9, 2021, seeking a base rate increase effective January 1, 2022, and a Generation Base Rate Adjustment for 2023 and 2024.
- The petition proposes the following base rate increases:
  - 2022 – US$295 million
  - 2023 – US$102 million
  - 2024 – US$26 million
- If approved as filed, Tampa Electric's rates would remain among the lowest in the state and below the national average; 2022 residential rates would be only 5 percent higher than they were more than a decade ago – about 17 percent lower when adjusted for inflation.
- A decision by the FPSC is expected by the end of 2021.

Emera

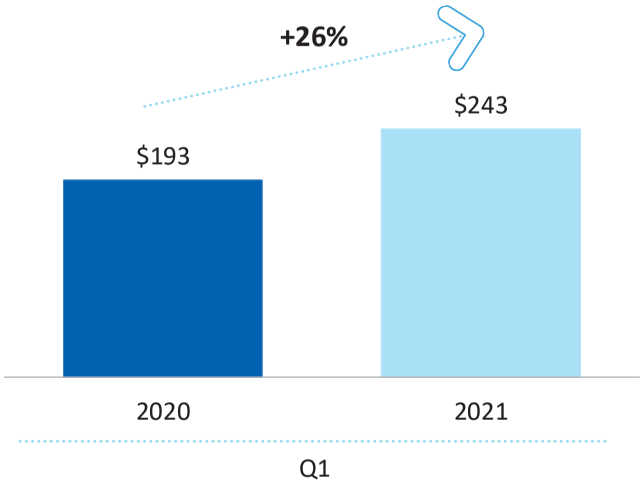
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FINANCIAL RESULTS

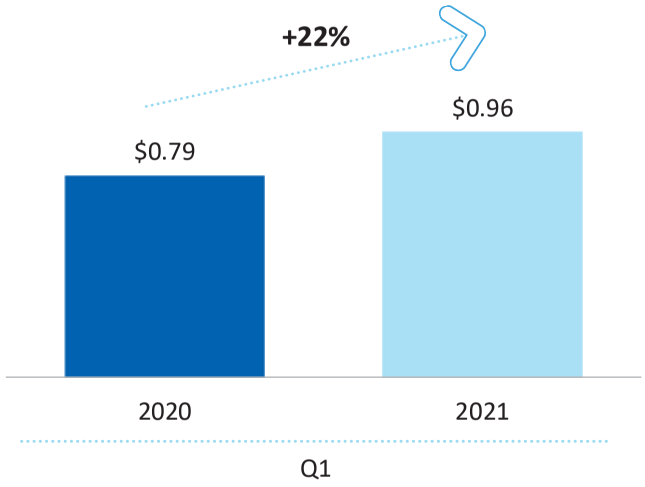
Emera

QUARTERLY ADJUSTED RESULTS

Adjusted Net Income[1]



Adjusted Earnings per Share[1]



[1] Adjusted net income and adjusted earnings per share are non-GAAP measures. See appendixx for reconciliation to the nearest GAAP measure.

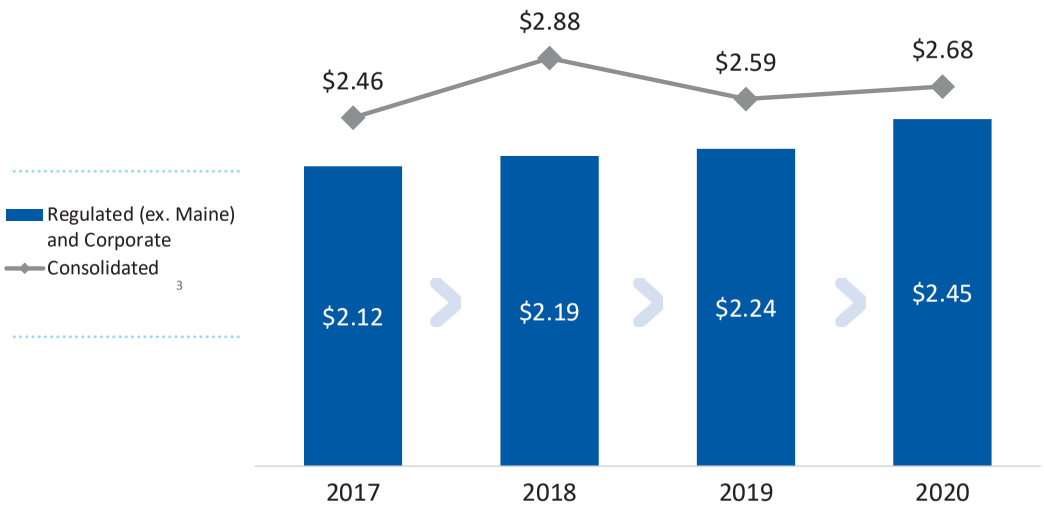
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CONSISTENTLY GROWING UTILITY EARNINGS

Historical Adjusted Earnings per Share[1,2]



Since 2017, the first full year with TECO as part of our business, Regulated and Corporate adjusted EPS (excluding Emera Maine) has grown at an annualized rate of 5%.

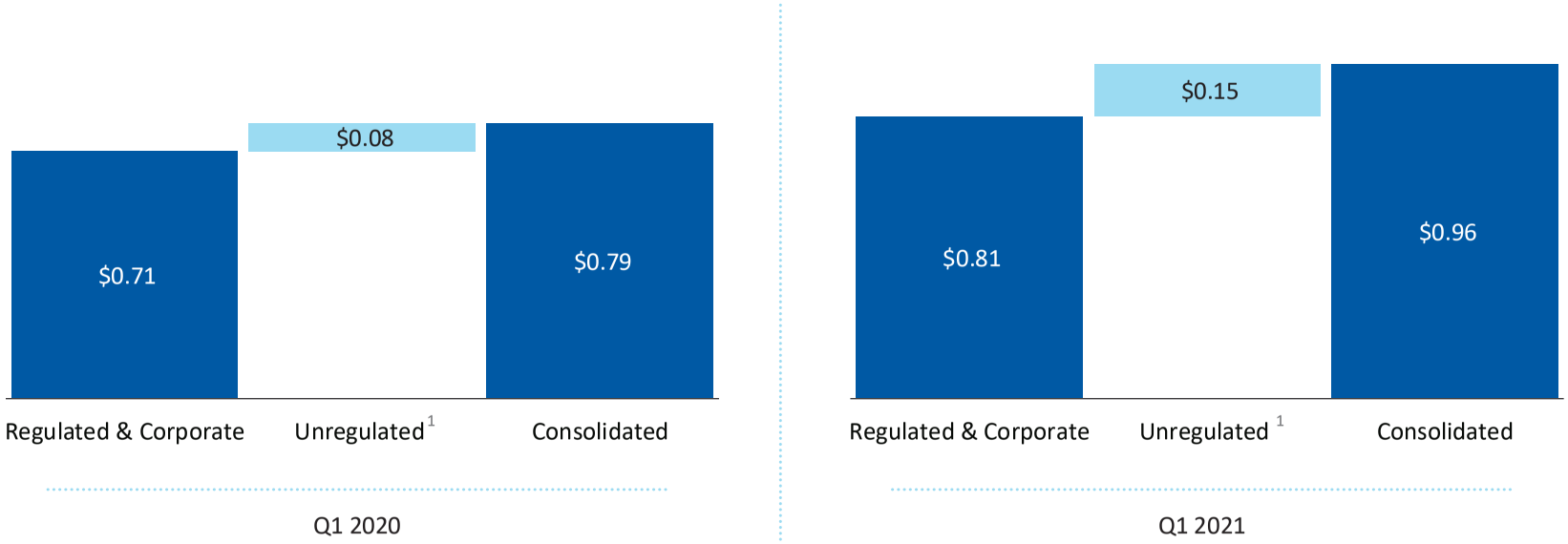
- Regulated and Corporate are the primary drivers of Emera's growth.
- Contributions from Emera Energy vary based on market conditions and cause variability in consolidated EPS; historically, this low-risk business has always generated positive earnings on an annual basis.

[1] Adjusted earnings per share is a non-GAAP measure. See reconciliation to nearest GAAP measure in the appendix; [2] Calculations of the components of adjusted EPS are included in the appendix; [3] Includes Tampa Electric, Nova Scotia Power, Emera Newfoundland, Emera Caribbean, Peoples Gas, New Mexico Gas, Emera New Brunswick, M&NP, Seacoast and Corporate

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COMPONENTS OF ADJUSTED EPS

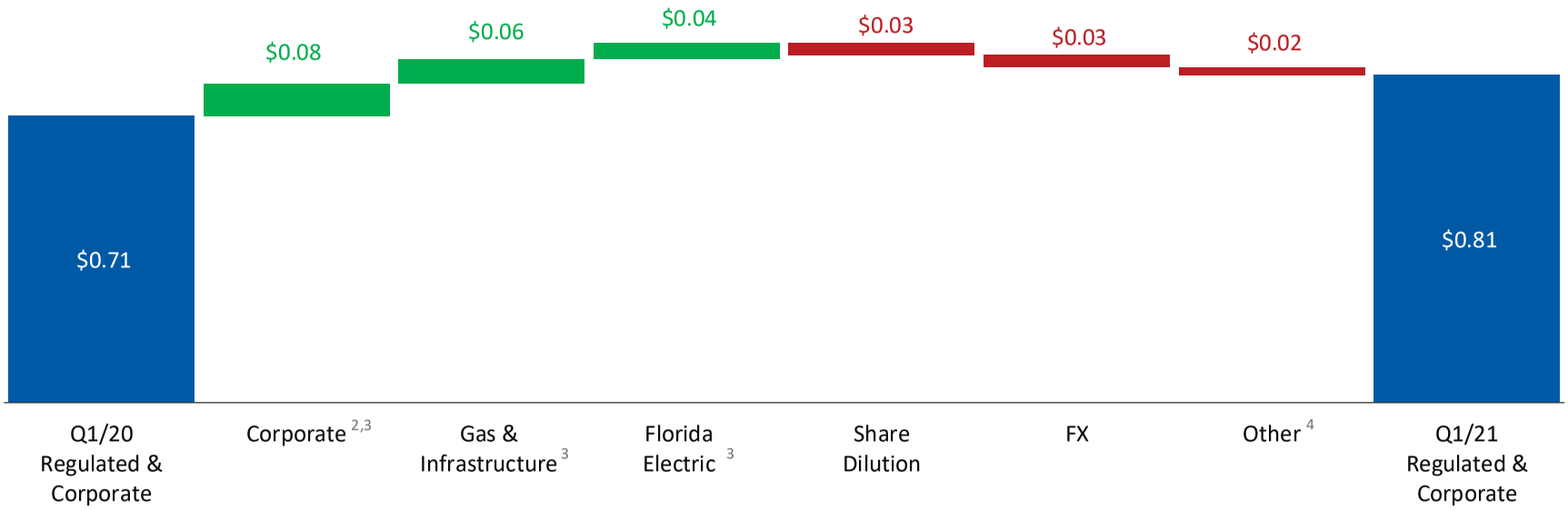


Emera

[1] Emera Energy earnings are strongest in Q1 and Q4. Over an annual period, Emera expects unregulated earnings to be approximately 5% of earnings.

KEY DRIVERS OF Q1/21 REGULATED AND CORPORATE GROWTH

Regulated and Corporate Adjusted EPS[1]



[1] Adjusted EPS is a non-GAAP measure. See appendix for reconciliation to nearest GAAP measure; [2] Includes $0.03 of LTIP-related savings that are expected to reverse out over the course of the year; [3] Excludes impact of the change in FX rate; [4] Includes Emera Maine (-$0.02), change in Other Utilities (+$0.02) and change in Canadian Utilities (-$0.02)

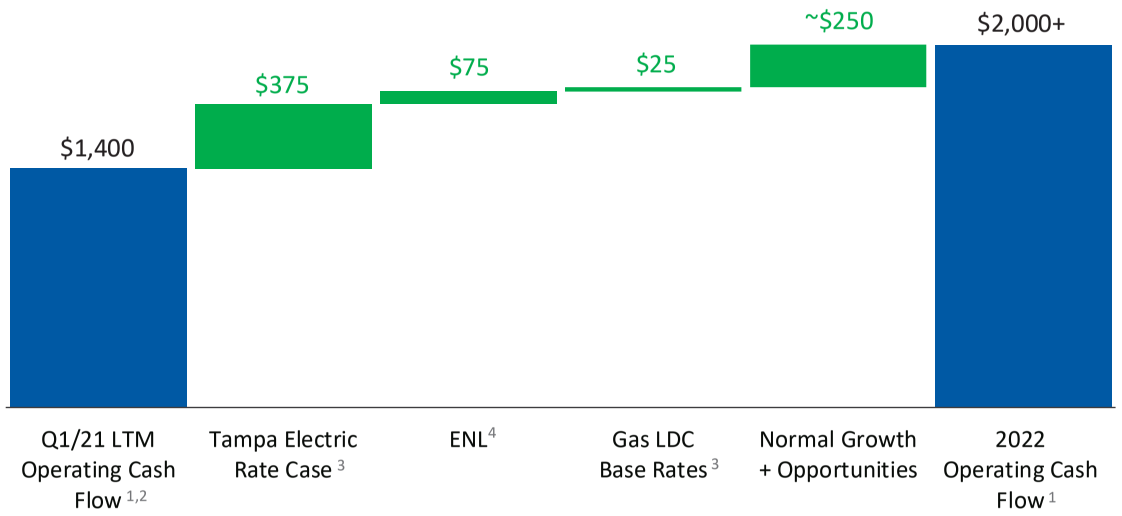
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STEP CHANGE IN OPERATING CASH FLOW

Operating Cash Flow Events
Next 12-24 Months



The expected step change in our operating cash flow and continued execution against our funding plan will enable us to successfully execute on our credit objectives:

- Maintain investment grade credit ratings
- Hold target capital structure
- Sustained cash flow-to-debt metrics > 12%
- Sustained holdco debt-to-total debt < 40%

[1] Before changes in net working capital; [2] Normalized for US$110 million of extraordinary gas costs incurred by New Mexico Gas in February; [3] USD cash flow is translated at a rate of 1.33; [4] Reflects dividends paid to Emera

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UPCOMING INVESTOR EVENTS

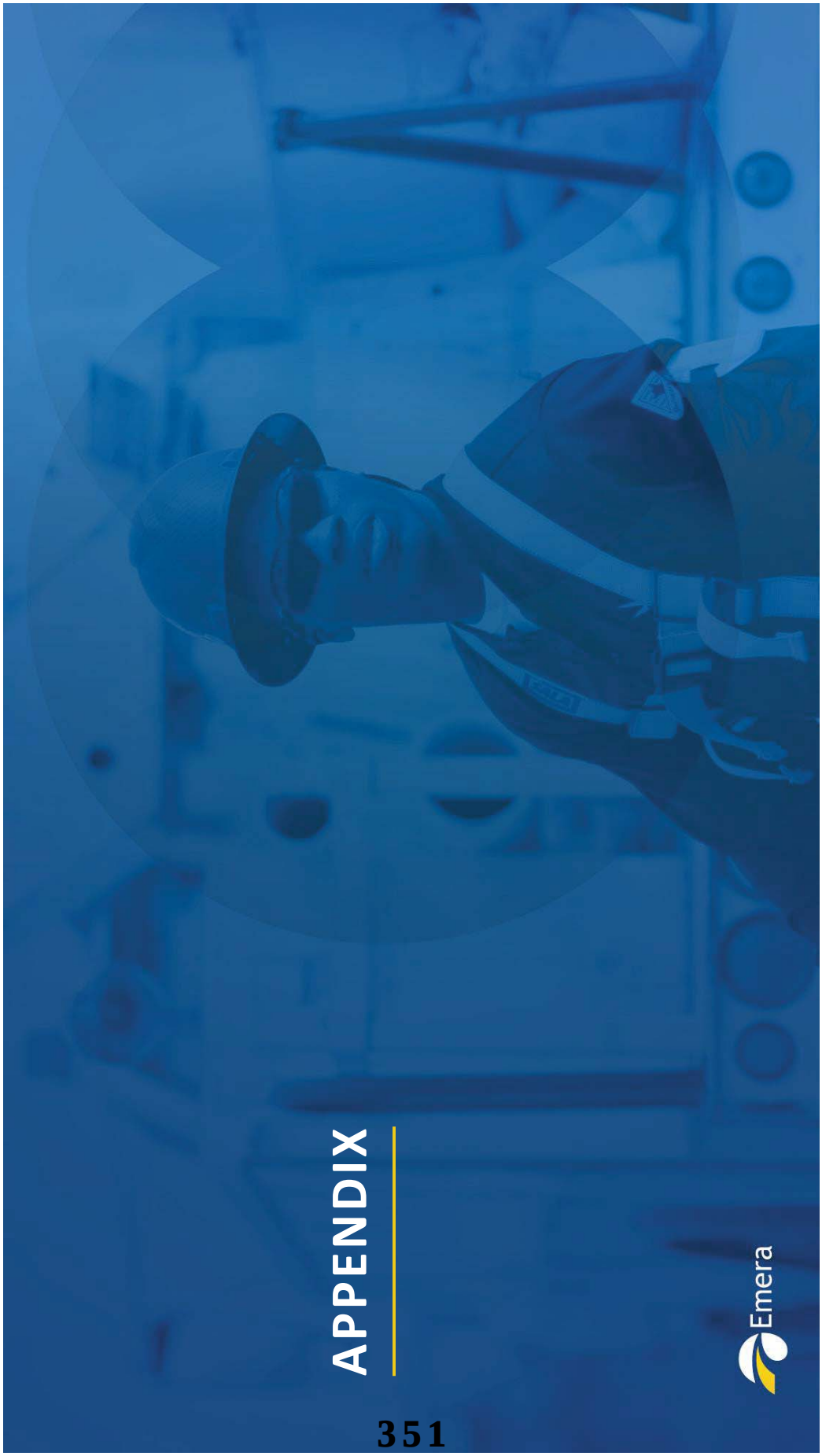
- **Annual General Meeting**
  Thursday, May 20, 2021
  investors.emera.com/2021-annual-meeting
- **Q2/21 Results & Analyst Call**
  Wednesday, August 11, 2021
- **Q3/21 Results & Analyst Call**
  Wednesday, November 10, 2021



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CAPITAL FORECAST BY AFFILIATE

Capital Forecast (CAD millions)[1]		2021F	2022F	2023F	Total
Tampa Electric	$	1,360	1,370	1,360	4,090
Peoples Gas		380	390	350	1,120
Seacoast		10	80	40	130
New Mexico Gas		130	140	140	410
Nova Scotia Power		395	365	380	1,130
Emera Caribbean		70	100	100	270
Emera Newfoundland		10	240	-	255
Other		5	20	10	40
Subtotal - Baseline Forecast	**$**	**2,360**	**2,705**	**2,380**	**7,445**
Add: Opportunities Under Development		170	440	590	1,200
Capital Forecast (CAD millions)	**$**	**2,530**	**3,145**	**2,970**	**8,645**

[1] Average total rate base in billions of Canadian dollars. U.S. dollar denominated rate base is translated at a forecasted exchange rate of 1.28 in 2021 and 1.33 in 2022-2023.

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RATE BASE FORECAST BY AFFILIATE

Rate Base Forecast (CAD millions)[1]		2019A	2020A	2021F	2022F	2023F	2019-2023 CAGR
Tampa Electric[2]	$	9,225	10,400	10,895	12,215	13,015	9.0%
Peoples Gas[2]		1,450	1,760	2,095	2,490	2,765	17.5%
Seacoast[3]		85	185	185	235	270	33.5%
Emera New Brunswick[3]		460	450	445	435	430	-1.7%
New Mexico Gas		775	855	960	1,015	1,060	8.1%
Nova Scotia Power		4,100	4,225	4,430	4,580	4,770	3.9%
Emera Caribbean		950	970	985	1,035	1,040	2.3%
Maritime Link		1,825	1,840	1,825	1,785	1,725	-1.4%
Labrador Island Link[4]		550	605	655	880	880	12.5%
Subtotal - Baseline Forecast	**$**	**19,420**	**21,290**	**22,475**	**24,670**	**25,955**	**7.5%**
Opportunities Under Development		-	-	90	390	910	
Rate Base Forecast (CAD millions)		**19,420**	**21,290**	**22,565**	**25,060**	**26,865**	**8.5%**

[1] Average rate base; US dollar denominated rate base is translated at a forecasted average USD/CAD exchange rate of 1.28 in 2021 and 1.33 in 2022-2023; [2] Capital structures that support the rate base include deferred tax liabilities (DTL), a zero cost-of-capital component of the capital structure in Florida; 2019 and 2020 capital structures included DTLs of $1,200 million at Tampa Electric and $200 million at Peoples Gas; [3] Reflects the capital asset values of the regulated pipeline investments; [4] Reflects Emera's equity investment in the project

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EMERA ENERGY QUARTERLY ADJUSTED EARNINGS CONTRIBUTION

Millions of Canadian dollars		Q2/19	Q3/19	Q4/19	Q1/20	Q2/20	Q3/20	Q4/20	Q1/21
Marketing and Trading	$	(20)	(19)	14	19	(11)	(11)	11	37
NEGG[1]		(2)	1	-	-	-	-	-	-
Maritimes Canada		(1)	-	(1)	(2)	-	1	-	-
Bear Swamp		4	4	4	4	4	(2)	4	5
Total (excl. MTM and loss on sale)	**$**	**(19)**	**(14)**	**17**	**21**	**(7)**	**(12)**	**15**	**43**
Net (loss)/gain on sale (recorded in Corporate)		(1)	-	-	-	-	-	-	

Millions of CAD dollars		2013	2014	2015	2016	2017	2018	2019	2020
Marketing and Trading Earnings	$	31	68	44	22	15	53	5	8
Average (2013 to 2020)	**$**	**31**							
Average (2013 to 2020) ex. outliers[1]	**$**	**39**							

[1] Excluding 2019 and 2020

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NON-GAAP RECONCILIATION

For the millions of Canadian dollars (except per share amounts)		Three months ended March 31	
		2021	2020
Net income attributable to common shareholders	$	**273**	523
Gain on sale, net of taxes and transaction costs		**-**	321
Impairment charges, net of tax		**-**	(23)
After-tax mark-to-market gain		**30**	32
Adjusted net income attributable to common shareholders	$	**243**	**193**
Weighted average shares		**253.5**	244.7
Earnings per common share – basic	$	**1.08**	**2.14**
Adjusted earnings per common share – basic	$	**0.96**	**0.79**

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REGULATED ADJUSTED EARNINGS GROWTH

Adjusted Earnings and EPS[1]	2017[2]	2018	2019	2020
Florida Electric Utility		381	419	501
Canadian Electric Utilities		218	229	221
Other Electric Utilities		89	76	33
Gas Utilities & Infrastructure		136	183	162
Regulated Adjusted Earnings	-	824	907	917
Less: Emera Maine		(44)	(47)	(6)
Corporate		(269)	(322)	(303)
Regulated & Corporate Adjusted Earnings (ex. Maine)	**452**	**511**	**538**	**608**
Emera Maine	46	44	47	6
Unregulated earnings[3]	26	116	36	51
Consolidated Adjusted Earnings	**524**	**671**	**621**	**665**
Weighted average shares o/s	213	233	240	248
Regulated EPS (ex. Maine)		3.35	3.58	3.67
Corporate EPS		(1.16)	(1.34)	(1.22)
Regulated & Corporate EPS	2.12	2.19	2.24	2.45
Emera Maine	0.22	0.19	0.20	0.02
Unregulated EPS	0.12	0.50	0.15	0.21
Consolidated Adjusted EPS	**2.46**	**2.88**	**2.59**	**2.68**

[1] Adjusted earnings and adjusted EPS are non-GAAP measures. See appendix for reconciliation to closest GAAP measure;

[2] Emera resegmented its financial statements in 2018;

[3] Unregulated adjusted earnings is calculated as follows:

	2017	2018	2019	2020
Unregulated Adjusted Earnings				
Emera Energy	24	120	37	17
Other	2	(4)	(1)	(2)
TECO Guatemala				36
Total	**26**	**116**	**36**	**51**

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Second Quarter 2021
August 11, 2021
Emera

FORWARD LOOKING INFORMATION AND NON-GAAP MEASURES

Forward-Looking Information

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations include without limitation: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; future dividend growth; timing and costs associated with certain capital investment; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats, such as the COVID-19 novel coronavirus pandemic; market energy sales prices; labour relations; and availability of labour and management resources. Readers are cautioned not to place undue reliance on forward-looking information as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this document is qualified in its entirety by the above cautionary statements and, except as required by law, Emera undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

Nothing in this document should be construed as an offer or sale of securities of Emera or any other person.

Non-GAAP Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. Refer to the Non-GAAP Financial Measures section of our MD&A for further discussion of these items.

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EXHIBIT NO.

Scott
Balfour
President and CEO
2
BUSINESS UPDATE
Emera

CONTINUED ADJUSTED EARNINGS GROWTH

360

+ Continued strength in the regulated portfolio	▶ **Q2 2021 adjusted EPS increased by $0.06 to $0.54**
+ Lower corporate financing costs	▶ **Q2 2021 YTD adjusted EPS increased by $0.22 to $1.49**
+ Improved marketing and trading results	▶ **Q2 2021 Regulated & Corporate EPS increased $0.04 and $0.13 for the YTD period**
− Stronger CAD and higher share count	▶ **2021 Capex program on track**

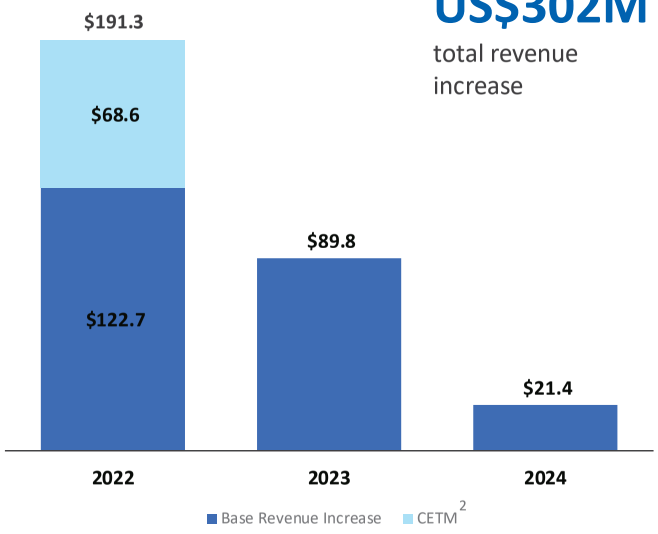
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TAMPA ELECTRIC RATE CASE

2022 - 2024 Revenue Increases[1]



US$302M
total revenue increase

Term

- 3-year term (2022 – 2024)

Assets

- Full, as filed cost recovery including:
  - Big Bend Modernization
  - Solar wave 2
  - Advanced Metering Infrastructure

Depreciation

- Increase in depreciation and dismantlement expense of US$17M
- New Clean Energy Transition Mechanism (CETM), for full recovery of retiring assets

Return on Equity and Equity Ratio

- ROE range of 9% - 11% (midpoint of 9.95%)
- 54% equity ratio
- Mechanism to increase ROE by 0.25% under certain conditions

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[1] In millions US$; [2] Clean Energy Transition Mechanism

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MARITIME LINK UPDATE

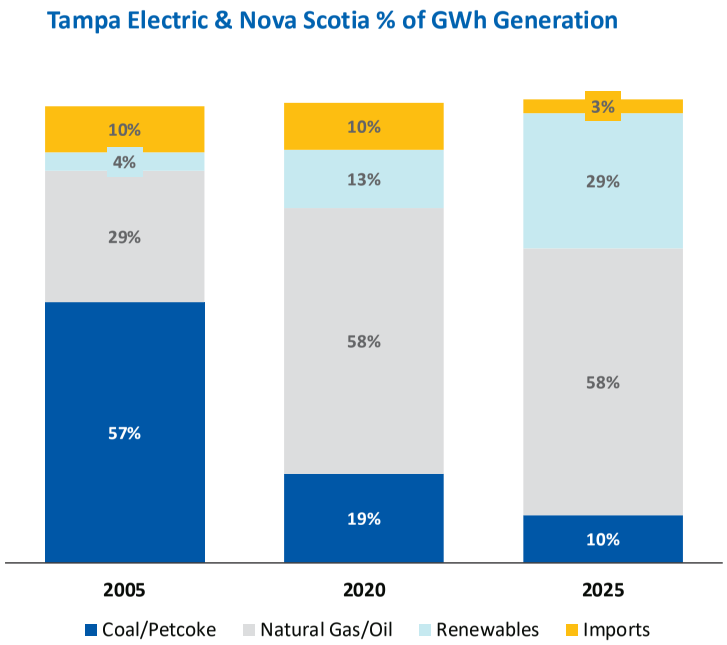
- Commencement of Nova Scotia Block starting August 15, 2021
- Will deliver clean renewable energy to Nova Scotia across the Maritime Link
- Puts Nova Scotia on track to generate approximately 60% of its electricity from renewable sources in 2022



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PROGRESS ON THE ENVIRONMENT



Significant Investments

Completed

- [x] ~600 MW of wind generation capacity installed in Nova Scotia
- [x] 630 MW of solar capacity added in Florida
- [x] Two coal units retired at the Big Bend power station
- [x] Construction of the Maritime Link and Labrador Island Link
- [x] The Nova Scotia Block to begin this month

In Progress

- [ ] Testing post-conversion unit 1 of the Big Bend power station – retiring unit 3 by 2023
- [ ] Additional 600 MW of solar generation to be installed in Florida
- [ ] Grid hardening and replacement of aging infrastructure continues as planned
- [ ] Battery storage integrated with solar

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2020 SUSTAINABILITY REPORT HIGHLIGHTS

Environment

39% reduction in CO_2 emissions since 2005

1,262 MW installed renewable capacity

$4.6B+ planned capital spending on cleaner, more reliable energy through 2023

1,250 MW solar capacity at Tampa Electric by end of 2023

Social

A Top 100 Employer in Canada for 2021; 3rd consecutive year

40,470 hours volunteered by Emera Inc. employees

$16M invested in our communities in 2020, with $6M for COVID-19 relief

41% of senior leaders at Emera are women; 34% across the company[1]

Governance

36% of directors are women, including the Chair

98% shareholder support for 2021 say on pay vote

33% are Black, Hispanic, or Indigenous[2]

48% of directors for our four largest utilities are female[2], and

Emera

As of December 31, 2020, unless otherwise indicated; *[1] 'Senior Leaders' refers to director and above;* *[2] As of August 9, 2021 and based on 21 Independent Directors at TEC, NSPI, PGS, & NMGC*

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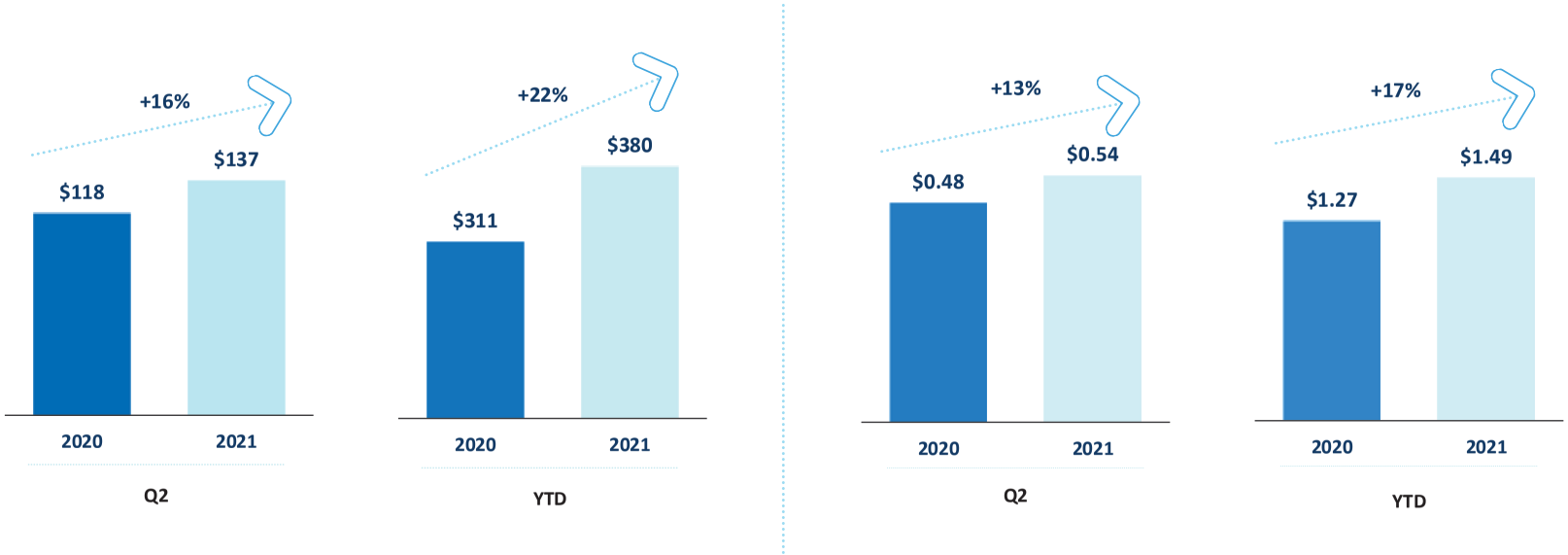
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FINANCIAL RESULTS

Emera

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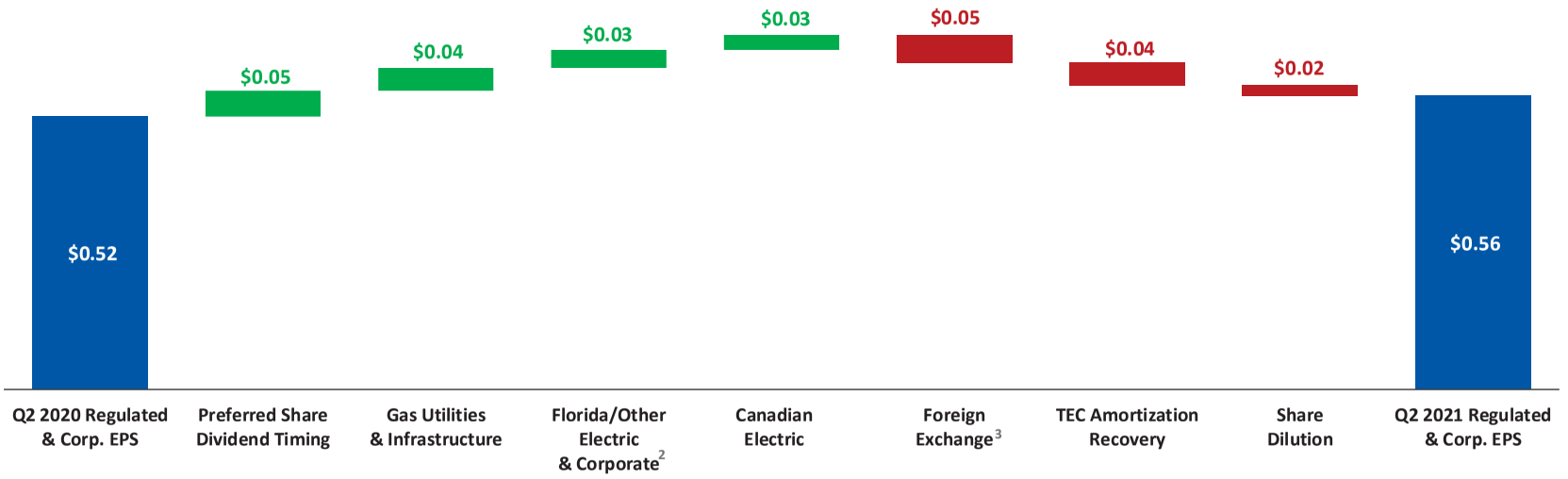
QUARTERLY ADJUSTED RESULTS



[1] Adjusted net income and adjusted earnings per share are non-GAAP measures. See appendix for reconciliation to the nearest GAAP measure.

KEY DRIVERS OF Q2/21 REGULATED AND CORPORATE GROWTH

Regulated and Corporate Adjusted EPS[1]



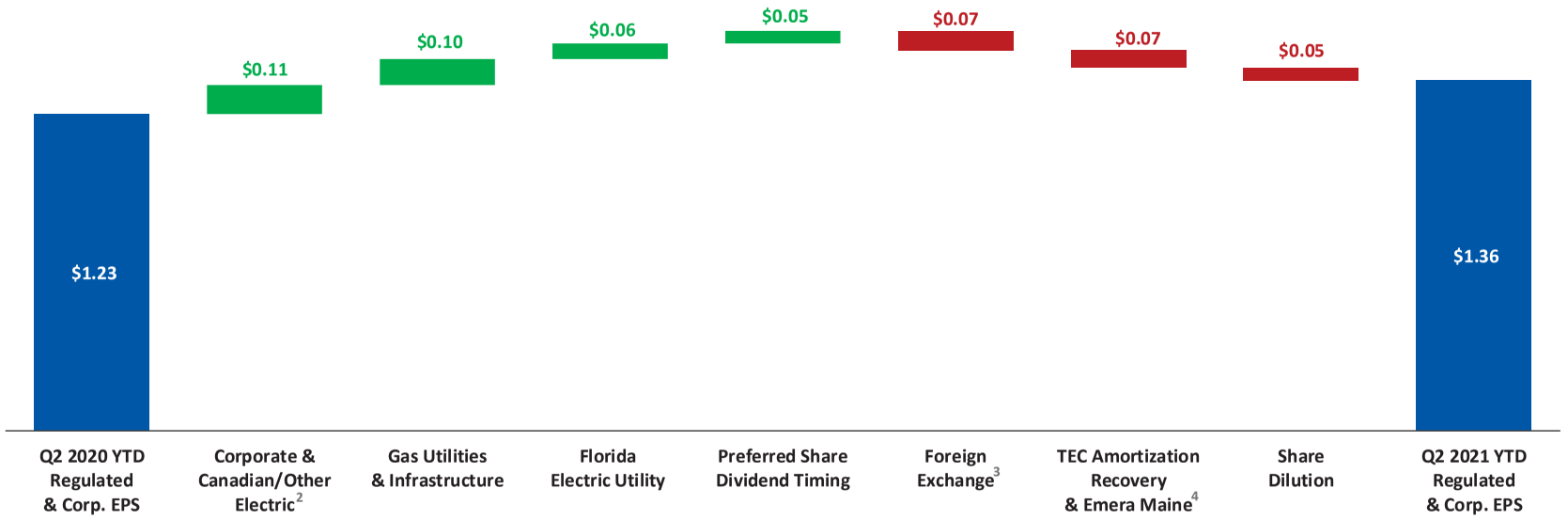
[1] Adjusted EPS is a non-GAAP measure. See appendix for reconciliation to nearest GAAP measure; [2] Includes $0.02 contribution from Florida Electric Utility, $0.01 contribution from Corporate, and an immaterial contribution from Other Electric Utilities; [3] Does not include FX impact from Emera Energy

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KEY DRIVERS OF Q2/21 YTD REGULATED AND CORPORATE GROWTH

YTD Regulated and Corporate Adjusted EPS[1]

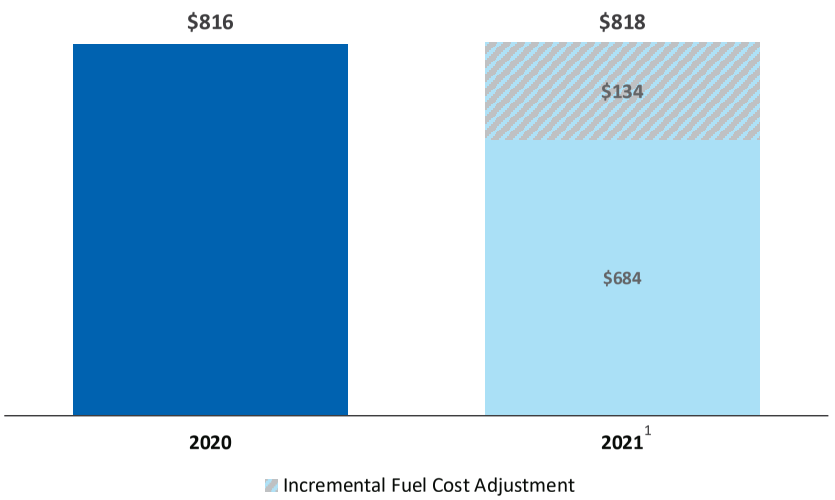


[1] Adjusted EPS is a non-GAAP measure. See appendix for reconciliation to nearest GAAP measure; [2] Includes a $0.09 favorable contribution from Corporate, a $0.02 favorable contribution from Other Electric Utilities (excluding Maine), and an immaterial contribution from Canadian Electric Utilities; [3] Does not include FX impact from Emera Energy; [4] Includes the loss of earnings contribution from an amortization recovery received at TEC in Q2 2020 ($0.04), and Emera Maine ($0.03)

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CASH FLOW EVENTS

YTD Operating Cash Flow
Before changes in working capital



Completed

- ☑ Agreement to increase rates at Tampa Electric and, rate increases effective January 1, 2021 at our Gas Utilities
- ☑ Regulatory approval for the recovery of US$108M in fuel costs at NMGC, related to the winter weather event
- ☑ Mid-course adjustment of US$83M at Tampa Electric
- ☑ Maritime Link collecting depreciation

Active

- ☐ Tampa Electric to increase revenues by US$191M in 2022
- ☐ Labrador Island Link to provide cash earnings in 2022

[1] Includes negative cash impact of US$108M (CAD$134M) at NMGC as a result of increased fuel costs due to the winter weather event – fuel costs will be recovered through rates over a 30-month period starting July 1, 2021

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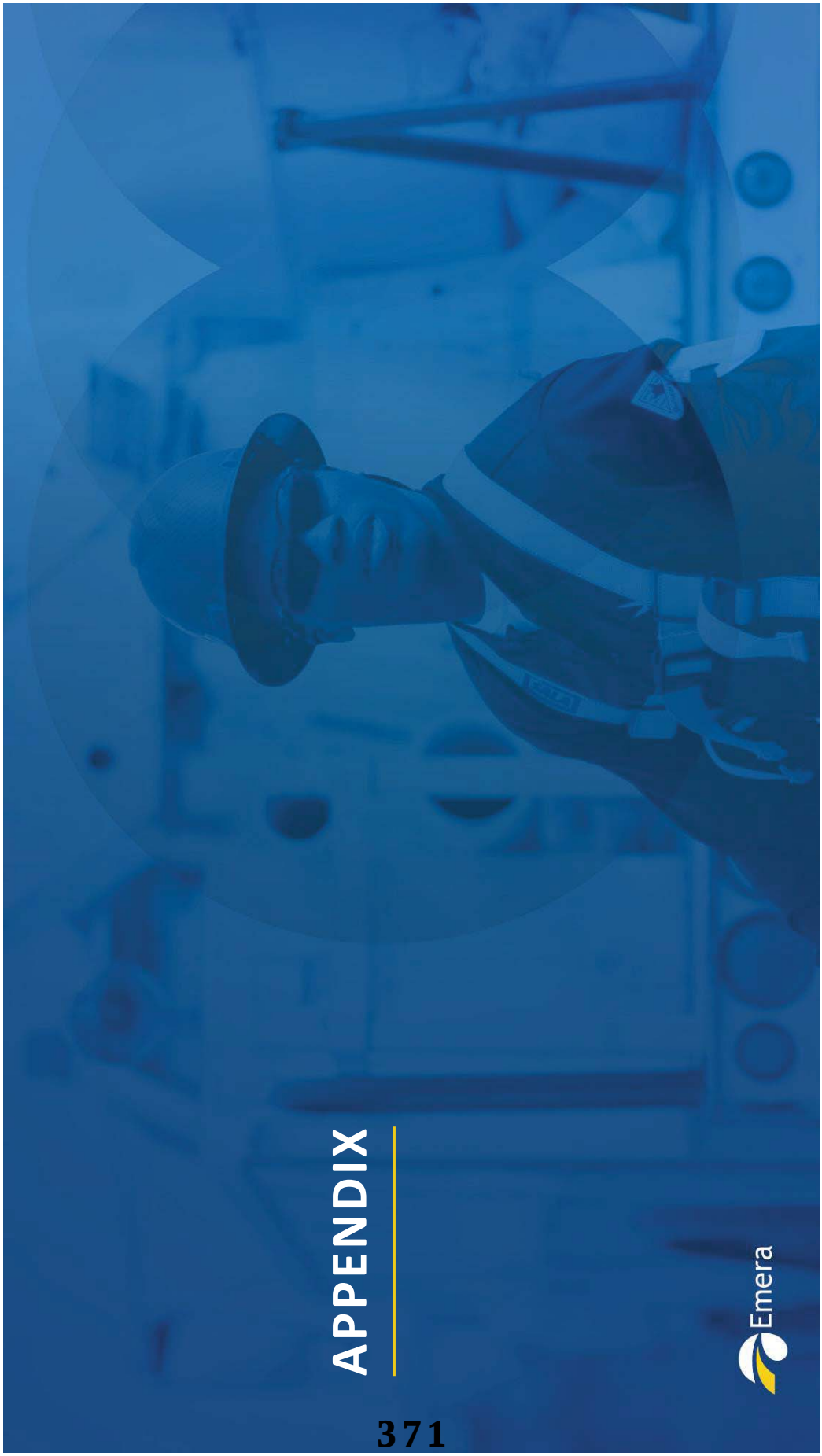
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UPCOMING INVESTOR EVENTS

- **Q3/21 Results & Analyst Call**
  Wednesday, November 10, 2021
- **Analyst Day – Toronto**
  Wednesday, December 1, 2021
- **Q4/21 Results & Analyst Call**
  February 2022

Emera


APPENDIX
Emera

CAPITAL FORECAST BY AFFILIATE

Capital Forecast (CAD millions)[1]		2021F	2022F	2023F	Total
Tampa Electric	$	1,360	1,370	1,360	4,090
Peoples Gas		380	390	350	1,120
Seacoast		10	80	40	130
New Mexico Gas		130	140	140	410
Nova Scotia Power		395	365	380	1,130
Emera Caribbean		70	100	100	270
Emera Newfoundland		10	240	-	255
Other		5	20	10	40
Subtotal - Baseline Forecast	**$**	**2,360**	**2,705**	**2,380**	**7,445**
Add: Opportunities Under Development		170	440	590	1,200
Capital Forecast (CAD millions)	**$**	**2,530**	**3,145**	**2,970**	**8,645**

[1] Average total rate base in billions of Canadian dollars. U.S. dollar denominated rate base is translated at a forecasted exchange rate of 1.28 in 2021 and 1.33 in 2022-2023.

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RATE BASE FORECAST BY AFFILIATE

Rate Base Forecast (CAD millions)[1]		2019A	2020A	2021F	2022F	2023F	2019-2023 CAGR
Tampa Electric[2]	$	9,225	10,400	10,895	12,215	13,015	9.0%
Peoples Gas[2]		1,450	1,760	2,095	2,490	2,765	17.5%
Seacoast[3]		85	185	185	235	270	33.5%
Emera New Brunswick[3]		460	450	445	435	430	-1.7%
New Mexico Gas		775	855	960	1,015	1,060	8.1%
Nova Scotia Power		4,100	4,225	4,430	4,580	4,770	3.9%
Emera Caribbean		950	970	985	1,035	1,040	2.3%
Maritime Link		1,825	1,840	1,825	1,785	1,725	-1.4%
Labrador Island Link[4]		550	605	655	880	880	12.5%
Subtotal - Baseline Forecast	**$**	**19,420**	**21,290**	**22,475**	**24,670**	**25,955**	**7.5%**
Opportunities Under Development		-	-	90	390	910	
Rate Base Forecast (CAD millions)		**19,420**	**21,290**	**22,565**	**25,060**	**26,865**	**8.5%**

[1] Average rate base; US dollar denominated rate base is translated at a forecasted average USD/CAD exchange rate of 1.28 in 2021 and 1.33 in 2022-2023; [2] Capital structures that support the rate base include deferred tax liabilities (DTL), a zero cost-of-capital component of the capital structure in Florida; 2019 and 2020 capital structures included DTLs of $1,200 million at Tampa Electric and $200 million at Peoples Gas; [3] Reflects the capital asset values of the regulated pipeline investments; [4] Reflects Emera's equity investment in the project

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EMERA ENERGY QUARTERLY ADJUSTED EARNINGS CONTRIBUTION

Millions of Canadian dollars		Q3/19	Q4/19	Q1/20	*Q2/20*	Q3/20	Q4/20	Q1/21	*Q2/21*
Marketing and Trading	$	(19)	14	19	***(11)***	(11)	11	37	***(3)***
NEGG[1]		1	-	-	**-**	-	-	-	**-**
Maritimes Canada		-	(1)	(2)	**-**	1	-	-	**-**
Bear Swamp		4	4	4	***4***	(2)	4	5	***2***
Total (excl. MTM and loss on sale)	**$**	**(14)**	**17**	**21**	***(7)***	**(12)**	**15**	**43**	***(1)***

Millions of CAD dollars		2013	2014	2015	2016	2017	2018	2019	2020
Marketing and Trading Earnings	$	31	68	44	22	15	53	5	8
Average (2013 to 2020)	**$**	**31**							
Average (2013 to 2020) ex. outliers[1]	**$**	**39**							

[1] Excluding 2019 and 2020

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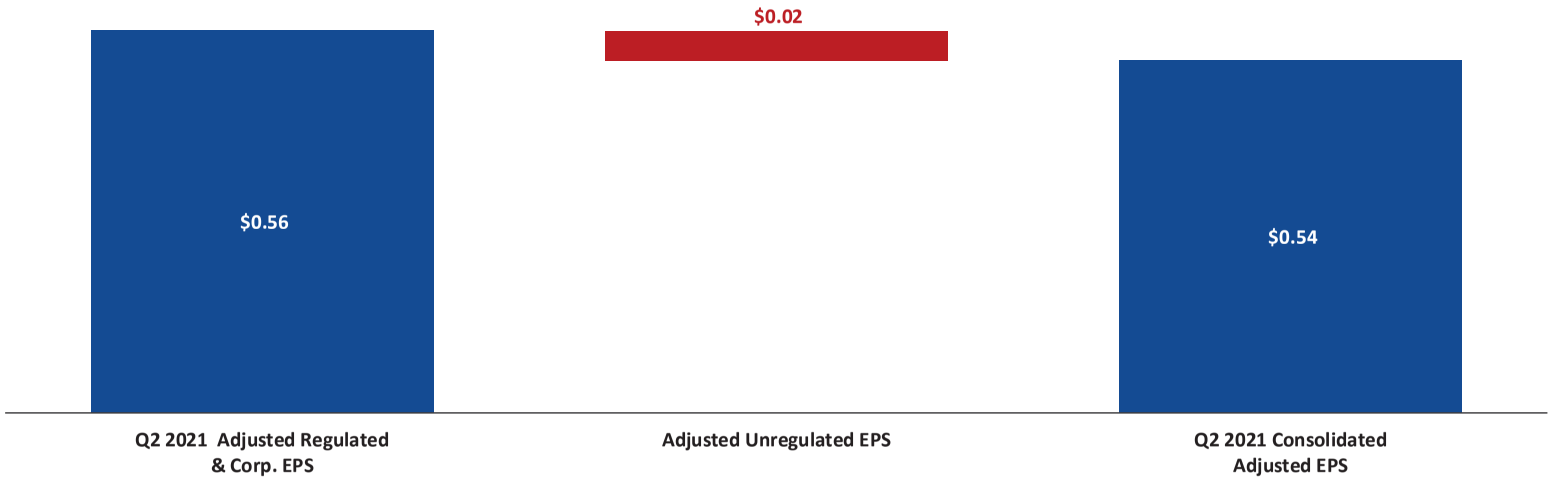
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NON-GAAP RECONCILIATION

For the millions of Canadian dollars (except per share amounts)		Three months ended June 30		Six months ended June 30	
		2021	2020	**2021**	2020
Net income (loss) attributable to common shareholders	$	**(17)**	58	**256**	581
Gain on sale, net of taxes and transaction costs		**-**	(12)	**-**	309
Impairment charges, net of tax		**-**	(3)	**-**	(26)
After-tax mark-to-market gain (loss)		**(154)**	(45)	**(124)**	(13)
Adjusted net income attributable to common shareholders	$	**137**	118	**380**	311
Weighted average shares		**255.8**	246.7	**254.6**	245.7
Earnings (loss) per common share – basic	$	**(0.07)**	0.24	**1.01**	2.37
Adjusted earnings per common share – basic	$	**0.54**	0.48	**1.49**	1.27

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Q2 2021 CONSOLIDATED ADJUSTED EPS RECONCILIATION



Despite improving $4M over Q2 2020 the unregulated business reported an adjusted loss of $5M in Q2 2021, a $0.02 unfavourable impact on consolidated adjusted EPS

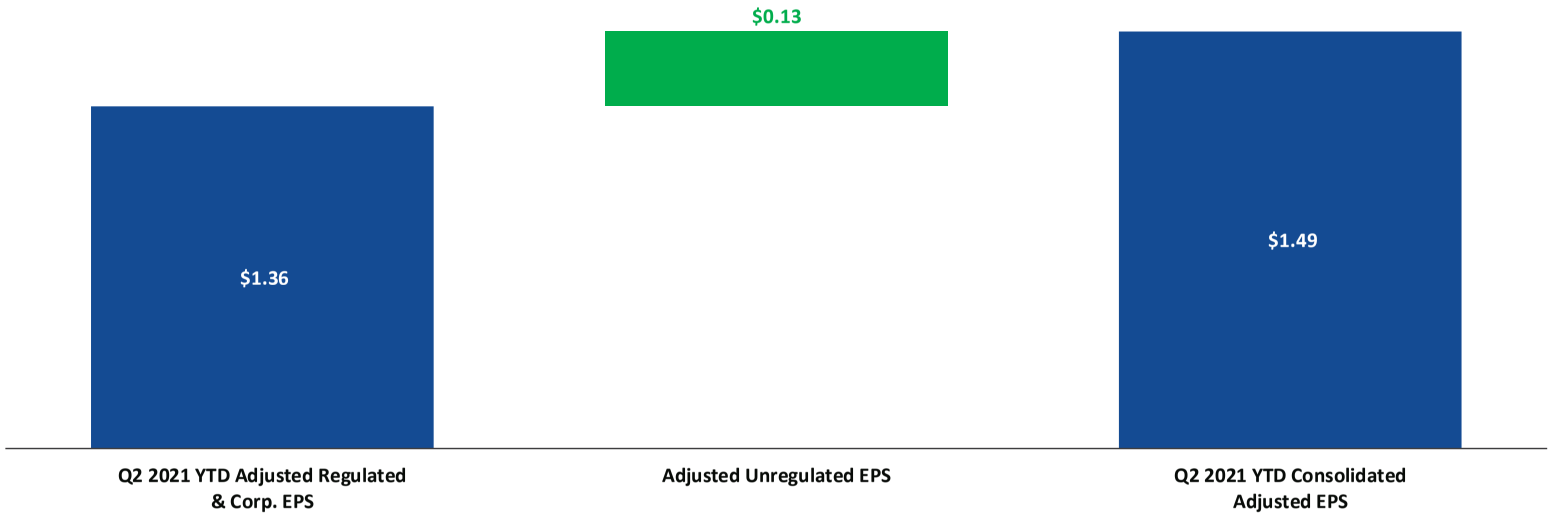
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Note: Adjusted EPS is a non-GAAP measure. See appendix for reconciliation to nearest GAAP measure

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Q2 2021 YTD CONSOLIDATED ADJUSTED EPS RECONCILIATION



The unregulated business reported adjusted earnings of $34M in YTD, a $0.13 favourable impact on consolidated adjusted EPS

Note: Adjusted EPS is a non-GAAP measure. See appendix for reconciliation to nearest GAAP measure

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REGULATED ADJUSTED EARNINGS GROWTH

Adjusted Earnings and EPS[1]	2017[2]	2018	2019	2020
Florida Electric Utility		381	419	501
Canadian Electric Utilities		218	229	221
Other Electric Utilities		89	76	33
Gas Utilities & Infrastructure		136	183	162
Regulated Adjusted Earnings	-	824	907	917
Less: Emera Maine		(44)	(47)	(6)
Corporate		(269)	(322)	(303)
Regulated & Corporate Adjusted Earnings (ex. Maine)	**452**	**511**	**538**	**608**
Emera Maine	46	44	47	6
Unregulated earnings[3]	26	116	36	51
Consolidated Adjusted Earnings	**524**	**671**	**621**	**665**
Weighted average shares o/s	213	233	240	248
Regulated EPS (ex. Maine)		3.35	3.58	3.67
Corporate EPS		(1.16)	(1.34)	(1.22)
Regulated & Corporate EPS	2.12	2.19	2.24	2.45
Emera Maine	0.22	0.19	0.20	0.02
Unregulated EPS	0.12	0.50	0.15	0.21
Consolidated Adjusted EPS	**2.46**	**2.88**	**2.59**	**2.68**

[1] Adjusted earnings and adjusted EPS are non-GAAP measures. See appendix for reconciliation to closest GAAP measure;

[2] Emera resegmented its financial statements in 2018;

[3] Unregulated adjusted earnings is calculated as follows:

	2017	2018	2019	2020
Unregulated Adjusted Earnings				
Emera Energy	24	120	37	17
Other	2	(4)	(1)	(2)
TECO Guatemala				36
Total	**26**	**116**	**36**	**51**

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Third Quarter 2021
November 10, 2021
Emera

FORWARD LOOKING INFORMATION AND NON-GAAP MEASURES

Forward-Looking Information

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors that could cause results or events to differ from current expectations include without limitation: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; future dividend growth; timing and costs associated with certain capital investment; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats, such as the COVID-19 novel coronavirus pandemic; market energy sales prices; labour relations; and availability of labour and management resources. Readers are cautioned not to place undue reliance on forward-looking information as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this document is qualified in its entirety by the above cautionary statements and, except as required by law, Emera undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

Nothing in this document should be construed as an offer or sale of securities of Emera or any other person.

Non-GAAP Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. Refer to the Non-GAAP Financial Measures section of our MD&A for further discussion of these items.

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Scott
Balfour
President and CEO
2
BUSINESS UPDATE
Emera

ON TRACK FOR A SOLID YEAR OF GROWTH

Millions of Canadian dollars (except per share amounts)	For the three months ended September 30, 2021			For the nine months ended September 30, 2021		
	Q3/21	**Q3/20**	*Delta*	**YTD 21**	**YTD 20**	*Delta*
Reported net income (loss)	$(70)	$84	*$(154)*	$186	$665	*$(479)*
Adjusted net income[1]	**$175**	**$166**	***$9***	**$555**	**$477**	***$78***
Reported earnings (loss) per share ("EPS")	$(0.27)	$0.34	*$(0.61)*	$0.73	$2.70	*$(1.97)*
Adjusted EPS[1]	**$0.68**	**$0.67**	***$0.01***	**$2.17**	**$1.93**	***$0.24***

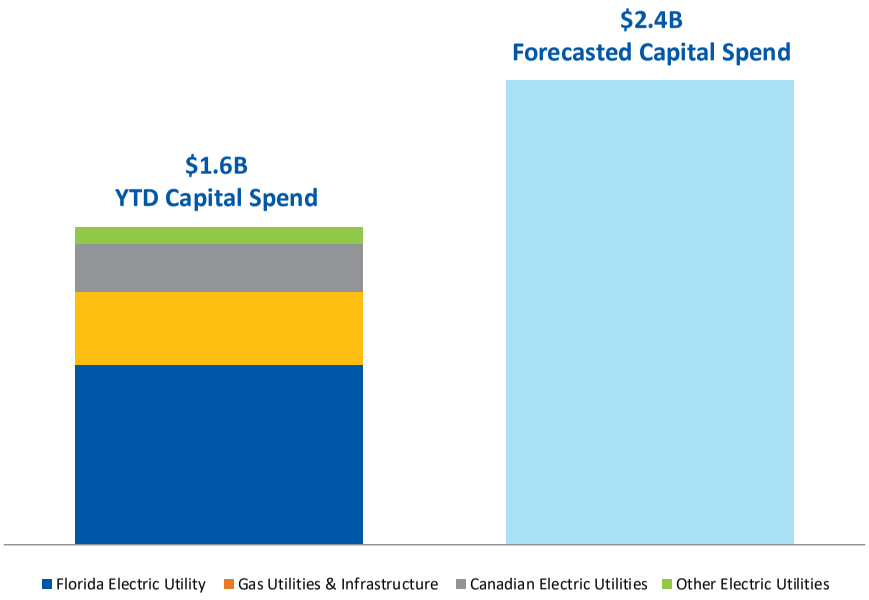


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[1] Adjusted net income and adjusted earnings per share are non-GAAP measures. See appendix for reconciliation to the nearest GAAP measure

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CAPITAL SPEND UPDATE



- On track to complete 2021 planned capital spend
- 70% of expected 2021 spend completed at Sept 30
- Big Bend modernization continues to advance
- Additional 225 MW of solar expected to be in service by Dec 31

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DELIVERING ON OUR CLIMATE COMMITMENT

Advancements

- Commencement of the Nova Scotia Block in August 2021

New Nova Scotia Provincial Decarbonization Goals

- 80% of energy to be from renewable resources by 2030
- Elimination of coal generation by 2030
- Supports the Eastern Clean Energy Initiative ("ECEI")
  - Additional wind generation
  - The introduction of battery storage
  - Transmission projects spanning multiple provinces



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REGULATORY UPDATE

RECENTLY COMPLETED

Affiliate	Approved Base Revenue Increase	Allowed ROE[1] & Equity Thickness	Highlights
Tampa Electric	2022: $191 million USD 2023: $90 million USD 2024: $21 million USD	Midpoint: 9.95% Range: 9.0% - 11.0% Equity: 54.0%	• Full, as filed capital plan, including the Big Bend Modernization, Solar Wave 2, and AMI; • Increase in depreciation and dismantlement expense of US$17M; • Clean Energy Transition Mechanism "CETM" allows for full recovery of retiring assets; • 25 bps increase in ROE range and mid-point (US$10M additional revenue), if U.S. Treasury Bond yields exceed a specified threshold.

UPCOMING

- **Nova Scotia Maritime Link:** Filed final capital cost application for Maritime Link and approval of NSPML's 2022 assessment. Decision expected in early 2022.
- **Barbados Light & Power:** Submitted a general rate review application in October 2021. The application seeks recovery of capital investments, results in annual revenue increase of ~US$23 million, includes a requested ROE of 12.5% and allowed equity structure of 65%. Decision expected by Q2 2022.
- **Grand Bahamas Power:** Filed an application for rate review in September 2021. Proposed rates would reinstate the amortization of regulatory assets deferred as part of the 5-year rate stabilization plan. The application included the request for an 8.5% to 9.0% allowed RORB[2] and target ROE of 12.84%. Decision is expected in Q4 2021.

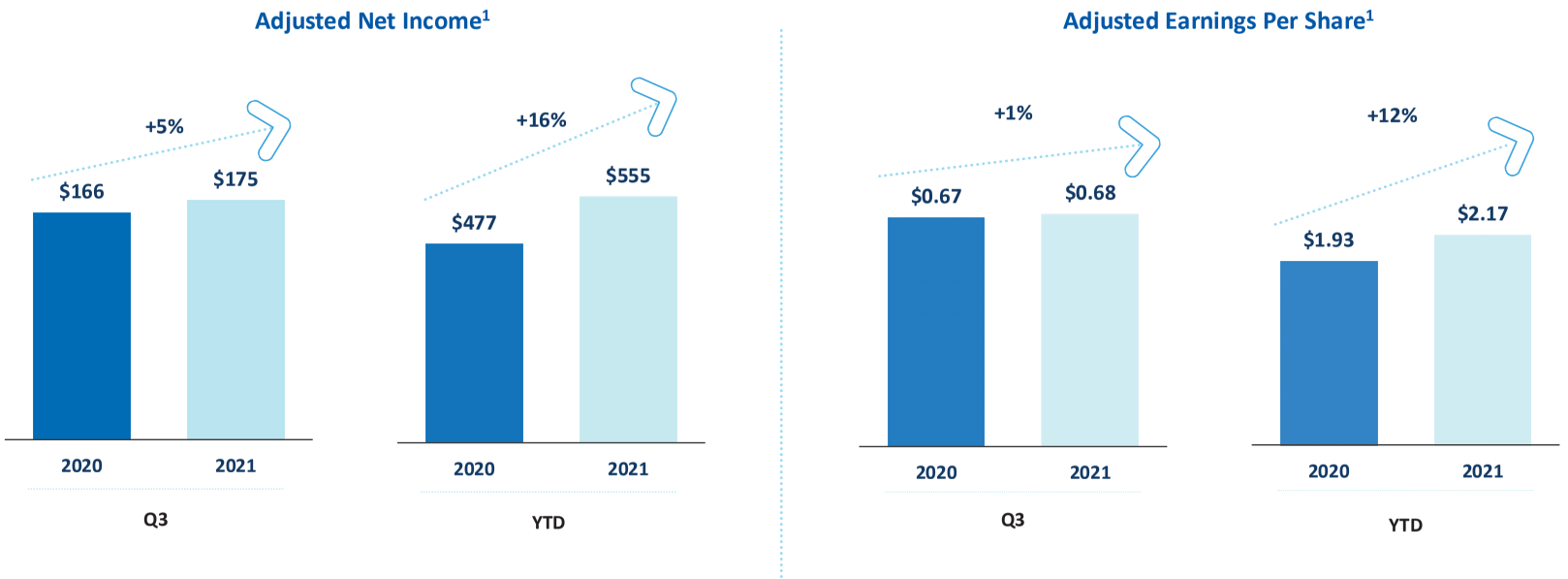
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[1] Return on Equity; [2] Regulated Return on Rate Base

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Greg
Blunden
CFO
7
FINANCIAL RESULTS
Emera

QUARTERLY ADJUSTED[1] RESULTS



[1] Adjusted net income and adjusted earnings per share are non-GAAP measures. See appendix for reconciliation to the nearest GAAP measure.

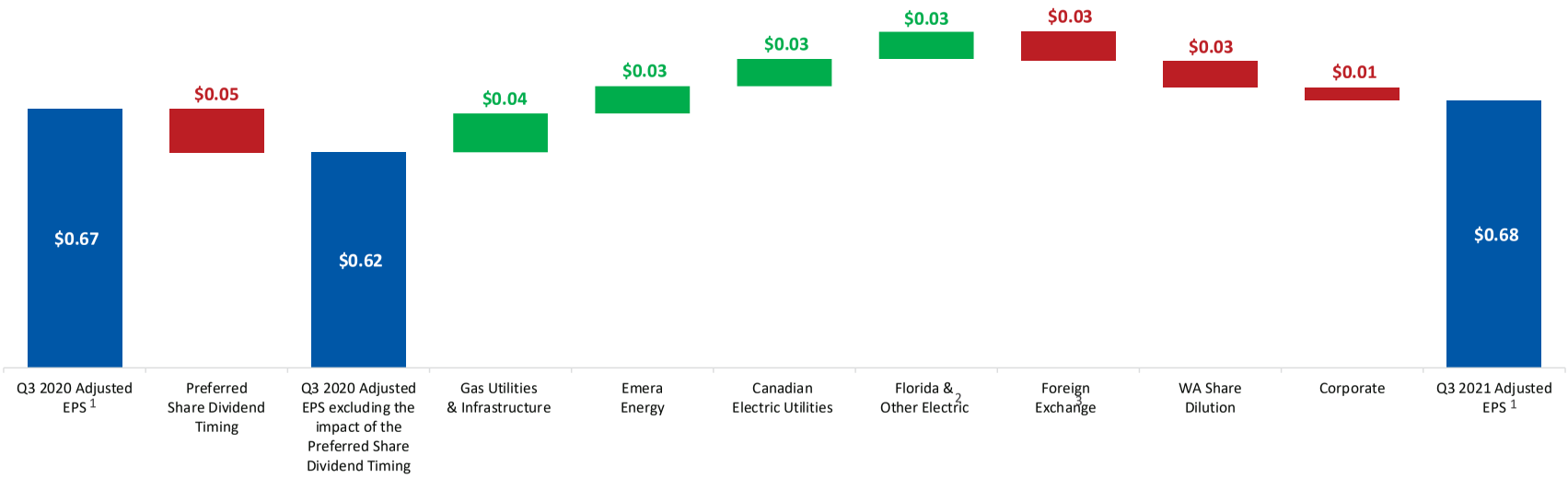
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KEY DRIVERS OF GROWTH IN Q3/21 ADJUSTED EPS[1]

Q3 2021 Adjusted EPS[1]



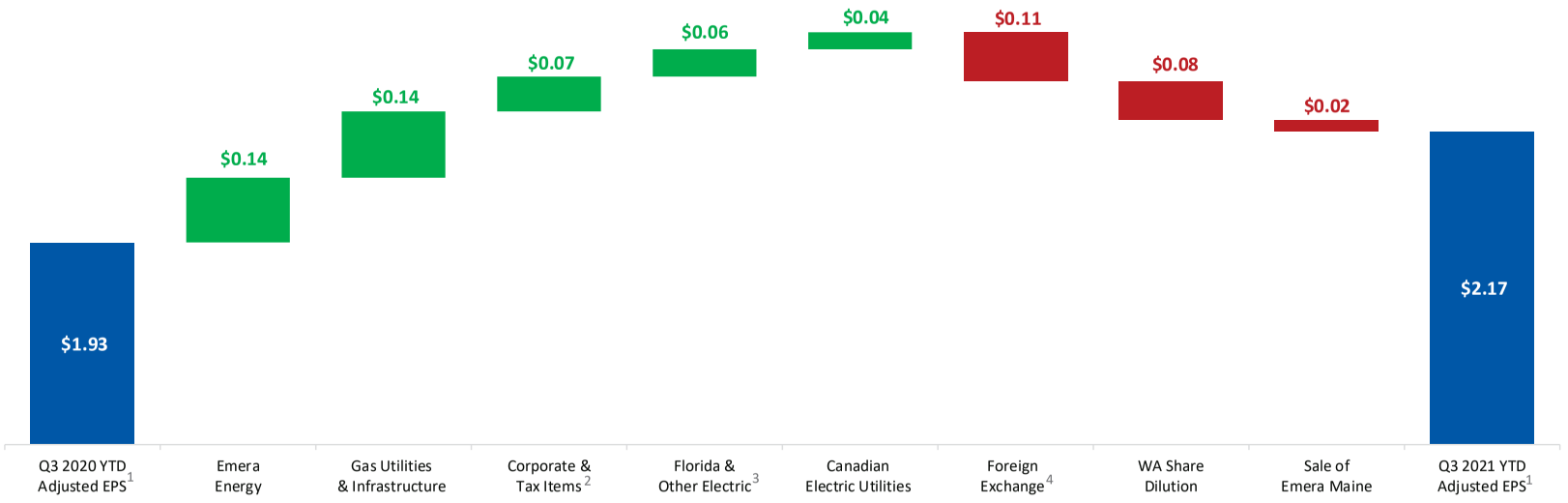
[1] Adjusted EPS is a non-GAAP measure. See appendix for reconciliation to nearest GAAP measure; [2] Includes a $0.02 contribution from Florida Electric Utility, and a $0.01 contribution from Other Electric Utilities; [3] Includes realized gain on FX hedges

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KEY DRIVERS OF GROWTH IN YTD ADJUSTED EPS[1]

Q3 2021 YTD Adjusted EPS[1]



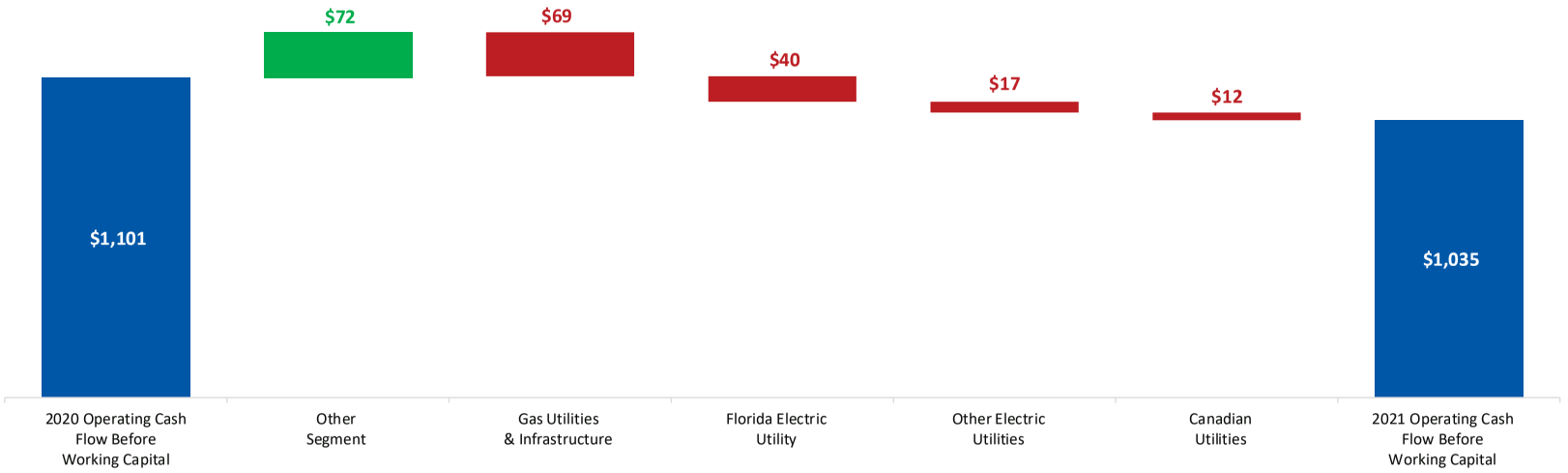
[1] Adjusted EPS is a non-GAAP measure; See appendix for reconciliation to nearest GAAP measure; [2] Includes a $0.06 contribution from Corporate and a $0.01 contribution from the 2020 tax revaluation in Nova Scotia and BLPC's 2020 tax recovery; [3] Includes a $0.03 contribution from Florida Electric Utility and a $0.03 contribution from Other Electric Utilities; [4] Includes realized gain on FX hedges

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CASH FLOWS

YTD Operating Cash Flow

Before changes in working capital
(millions of CAD$)



Although rising fuel costs have not had a material impact on earnings, they have put downward pressure on Emera's YTD operating cash flow before changes in working capital, as timing of recovery is balanced with affordability

Emera

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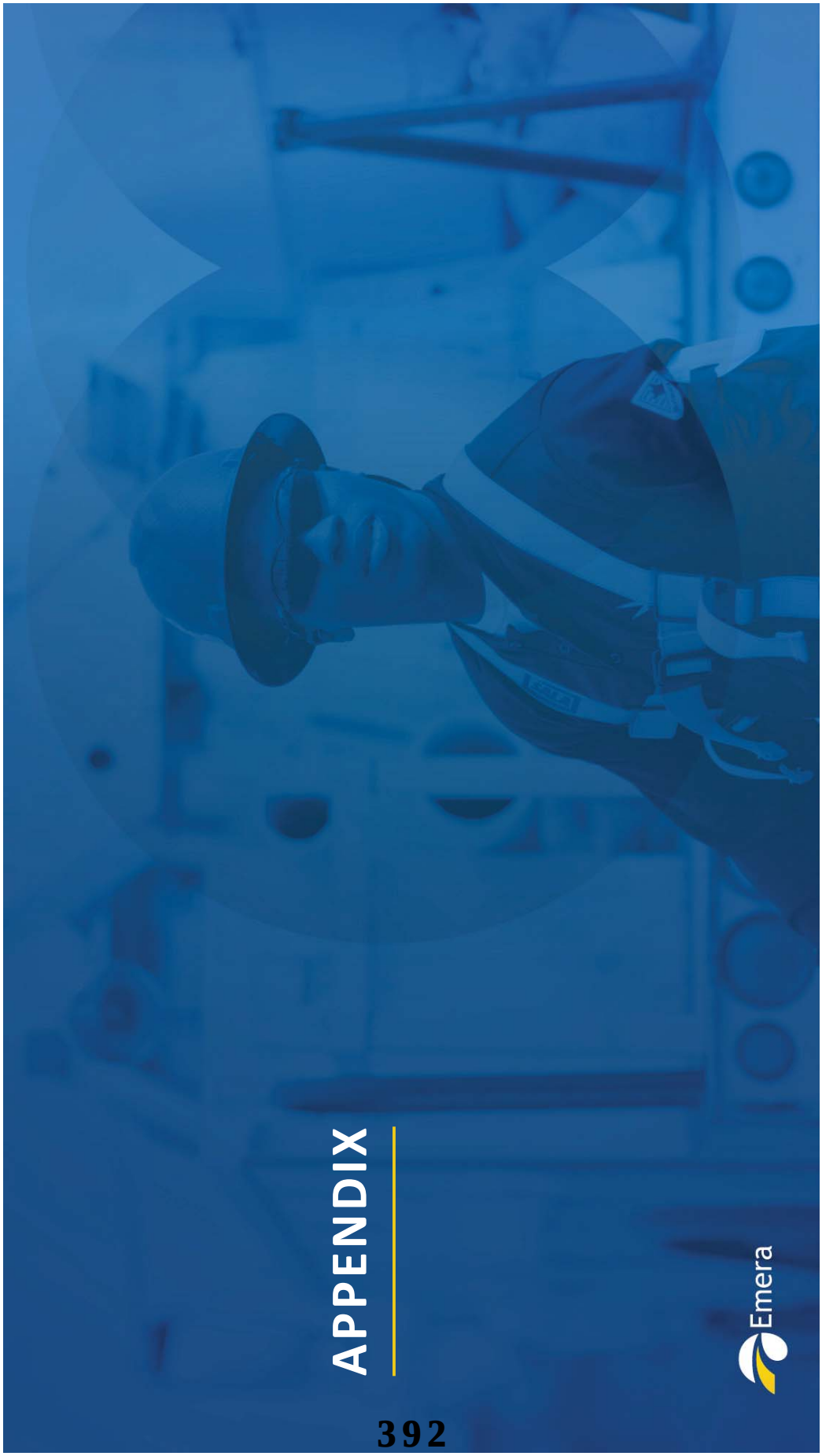
UPCOMING INVESTOR EVENTS

- **Analyst Day – Virtual**
  Wednesday, December 1, 2021
- **Q4/21 Results & Analyst Call**
  February 2022
- **Q1/22 Results & Analyst Call**
  May 2022



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Emera

CAPITAL FORECAST BY AFFILIATE

Capital Forecast (CAD millions)[1]		2021F	2022F	2023F	Total
Tampa Electric	$	1,360	1,370	1,360	4,090
Peoples Gas		380	390	350	1,120
Seacoast		10	80	40	130
New Mexico Gas		130	140	140	410
Nova Scotia Power		395	365	380	1,130
Emera Caribbean		70	100	100	270
Emera Newfoundland		10	240	-	255
Other		5	20	10	40
Subtotal - Baseline Forecast	**$**	**2,360**	**2,705**	**2,380**	**7,445**
Add: Opportunities Under Development		170	440	590	1,200
Capital Forecast (CAD millions)	**$**	**2,530**	**3,145**	**2,970**	**8,645**

[1] Average total capital forecast in billions of Canadian dollars. U.S. dollar denominated rate base is translated at a forecasted exchange rate of 1.28 in 2021 and 1.33 in 2022-2023.

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RATE BASE FORECAST BY AFFILIATE

Rate Base Forecast (CAD millions)[1]		2019A	2020A	2021F	2022F	2023F	2019-2023 CAGR
Tampa Electric[2]	$	9,225	10,400	10,895	12,215	13,015	9.0%
Peoples Gas[2]		1,450	1,760	2,095	2,490	2,765	17.5%
Seacoast[3]		85	185	185	235	270	33.5%
Emera New Brunswick[3]		460	450	445	435	430	-1.7%
New Mexico Gas		775	855	960	1,015	1,060	8.1%
Nova Scotia Power		4,100	4,225	4,430	4,580	4,770	3.9%
Emera Caribbean		950	970	985	1,035	1,040	2.3%
Maritime Link		1,825	1,840	1,825	1,785	1,725	-1.4%
Labrador Island Link[4]		550	605	655	880	880	12.5%
Subtotal - Baseline Forecast	**$**	**19,420**	**21,290**	**22,475**	**24,670**	**25,955**	**7.5%**
Opportunities Under Development		-	-	90	390	910	
Rate Base Forecast (CAD millions)		**19,420**	**21,290**	**22,565**	**25,060**	**26,865**	**8.5%**

[1] Average rate base; US dollar denominated rate base is translated at a forecasted average USD/CAD exchange rate of 1.28 in 2021 and 1.33 in 2022-2023; [2] Capital structures that support the rate base include deferred tax liabilities (DTL), a zero cost-of-capital component of the capital structure in Florida; 2019 and 2020 capital structures included DTLs of $1,200 million at Tampa Electric and $200 million at Peoples Gas; [3] Reflects the capital asset values of the regulated pipeline investments; [4] Reflects Emera's equity investment in the project

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EMERA ENERGY QUARTERLY ADJUSTED EARNINGS[1] CONTRIBUTION

Millions of Canadian dollars		Q4/19	Q1/20	Q2/20	*Q3/20*	Q4/20	Q1/21	Q2/21	***Q3/21***
Marketing and Trading	$	14	19	(11)	***(11)***	11	37	(3)	***(6)***
Maritimes Canada		(1)	(2)	-	***1***	-	-	-	-
Bear Swamp		4	4	4	***(2)***	4	5	2	***1***
Total Adjusted Net Income[1]	**$**	**17**	**21**	(7)	***(12)***	**15**	**43**	(1)	***(5)***

Millions of Canadian dollars		2013	2014	2015	2016	2017	2018	2019	2020
Marketing and Trading Adjusted Net Income[1]	$	31	68	44	22	15	53	5	8
Average (2013 to 2020)	**$**	**31**							
Average (2013 to 2020) ex. outliers[2]	**$**	**39**							

[1] Adjusted net income is a non-GAAP measure; See appendix for reconciliation to nearest GAAP measure; [2] Excludes 2019 and 2020

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NON-GAAP RECONCILIATION

For the *millions of Canadian dollars (except per share amounts)*		Three months ended September 30		Nine months ended September 30	
		2021	2020	**2021**	2020
Net income (loss) attributable to common shareholders	$	**(70)**	84	**186**	665
Gain on sale, net of taxes and transaction costs		**-**	-	**-**	309
Impairment charges, net of tax		**-**	-	**-**	(26)
After-tax mark-to-market loss		**(245)**	(82)	**(369)**	(95)
Adjusted net income attributable to common shareholders	$	**175**	166	**555**	477
Weighted average shares		**258.5**	248.4	**256.0**	246.6
Earnings (loss) per common share – basic	$	**(0.27)**	0.34	**0.73**	2.70
Adjusted earnings per common share – basic	$	**0.68**	0.67	**2.17**	1.93

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Fourth Quarter 2021
February 14, 2022
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FORWARD LOOKING INFORMATION, NON-GAAP MEASURES AND OTHER

Forward-Looking Information

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

The forward-looking information is based on reasonable assumptions and is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information.

Factors that could cause results or events to differ from current expectations include without limitation: regulatory risk; operating and maintenance risks; changes in economic conditions; commodity price and availability risk; liquidity and capital market risk; future dividend growth; timing and costs associated with certain capital investment; the expected impacts on Emera of challenges in the global economy; estimated energy consumption rates; maintenance of adequate insurance coverage; changes in customer energy usage patterns; developments in technology that could reduce demand for electricity; global climate change; weather; unanticipated maintenance and other expenditures; system operating and maintenance risk; derivative financial instruments and hedging; interest rate risk; counterparty risk; disruption of fuel supply; country risks; environmental risks; foreign exchange; regulatory and government decisions, including changes to environmental, financial reporting and tax legislation; risks associated with pension plan performance and funding requirements; loss of service area; risk of failure of information technology infrastructure and cybersecurity risks; uncertainties associated with infectious diseases, pandemics and similar public health threats, such as the COVID-19 novel coronavirus pandemic; market energy sales prices; labour relations; and availability of labour and management resources. Readers are cautioned not to place undue reliance on forward-looking information as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information.

qualified in its entirety by the above cautionary statements and, except as required by law, Emera undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

Nothing in this document should be construed as an offer or sale of securities of Emera or any other person.

Non-GAAP Measures

Emera uses financial measures that do not have standardized meaning under USGAAP and may not be comparable to similar measures presented by other entities. Emera calculates the non-GAAP measures by adjusting certain GAAP measures for specific items the Company believes are significant, but not reflective of underlying operations in the period. Refer to the "Non-GAAP Financial Measures" section of the Company's MD&A which is incorporated herein by reference and can be found on SEDAR at www.sedar.com. Reconciliation to the nearest GAAP measure is included in the appendix.

Other

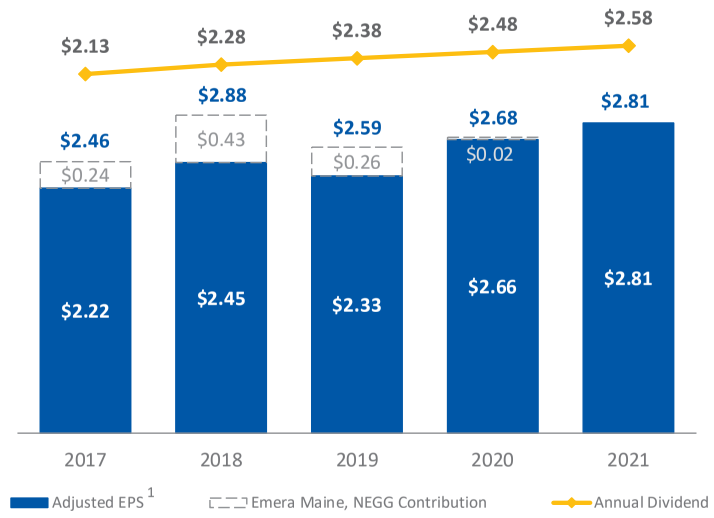
Rate base is a financial measure specific to rate-regulated utilities that is not intended to represent any financial measure as defined by GAAP. The measure is required by the regulatory authorities in the jurisdictions where Emera's rate-regulated subsidiaries or equity investments operate, a summary of which can be found in our MD&A. The calculation of this measure as presented may not be comparable to similarly titled measures used by other companies.

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EMERA'S 2021 ACHEIVEMENTS

FINANCIAL

- 2021 reported net income of $510M
- Record adjusted net income[1] of $723M
- Compound annual growth in adjusted net income[1] of 8% since 2017
- 15 years of predictable sustainable dividend growth









[1] Adjusted net income and adjusted earnings per share are non-GAAP measures. See appendix for reconciliation to nearest GAAP measure

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EMERA'S 2021 ACHEIVEMENTS

OPERATIONAL

- Achieved important regulatory outcomes
- Fully executed $2.4B 2021 capital plan
- $250M invested in grid reliability at Nova Scotia Power and Tampa Electric driving meaningful improvements in reliability
- Delivery of Nova Scotia Block of energy commenced in August 2021, final cost assessment approved in February 2022



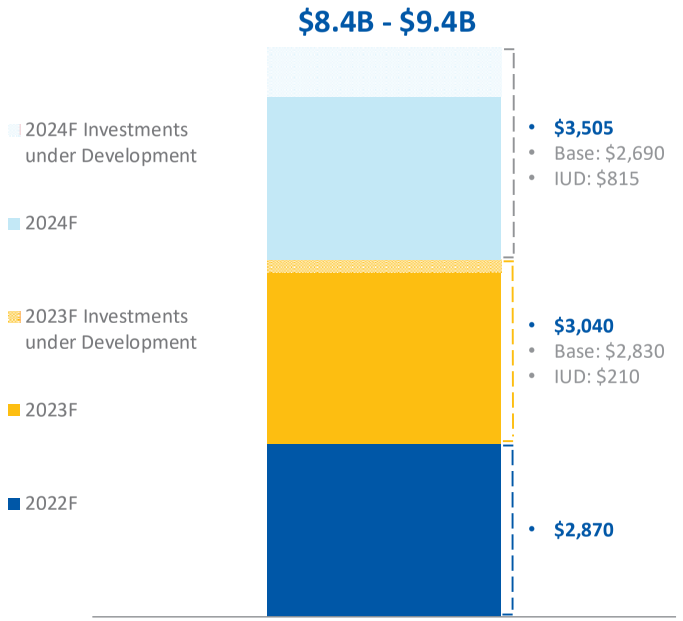
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INVESTING IN CLEANER, MORE RELIABLE ENERGY

Forecasted Capital Spend[1,2,3]

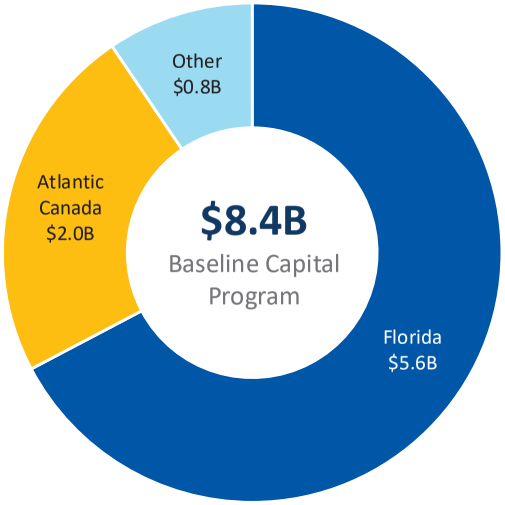


Capital Projects (2022 to 2024)[1,2]		Total
Tampa Electric - Solar Investments	$	815
Tampa Electric - Grid Modernization, AMI and LED		655
Tampa Electric - Storm Hardening		640
Nova Scotia Power - ECEI		500
Tampa Electric - Battery Storage		365
PGS & NMGC - Reliability Projects & CIBS/PP Investments		340
PGS& NMGC - RNG, CNG & LNG Projects		290
Labrador Island Link - Transmission Investment[2]		240
Nova Scotia Power - Hydro Renewal		210
Tampa Electric - Big Bend Modernization		170
Other Projects (Energy delivery upgrades, DG, storage, etc.)		1,100
Total	**$**	**5,325**
% of baseline capital program		**64%**

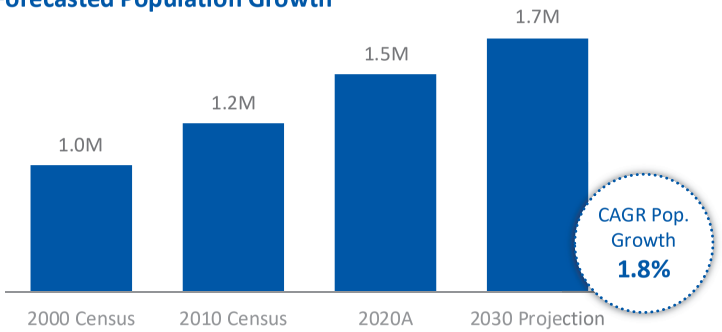
[1] Millions $CAD
[2] US dollar denominated capex is translated at a forecasted average USD/CAD exchange rate of $1.30 in 2022-2024.
[3] In addition to capital spend, includes $240M of additions to Emera's equity investment in LIL in 2022. Capital forecast by affiliate can be found in the appendix.

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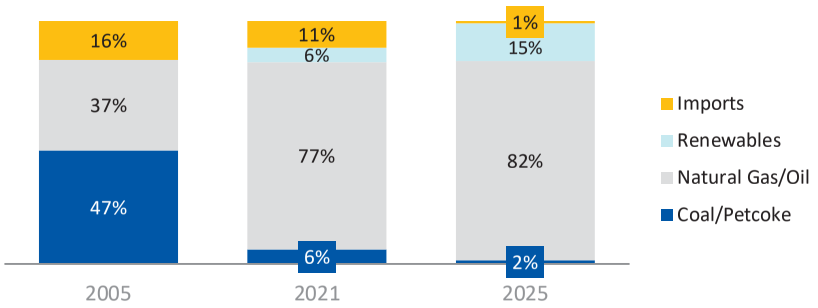
INVESTMENT IN FLORIDA



Forecasted Population Growth[1]



Reducing coal generation by investing in solar and natural gas[2,3]



[1] For Hillsborough County. Source: US Census and Tampa Hillsborough Economic Development Corporation
[2] GWh total generation mix
[3] Based on forecasted fuel prices

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REGULATORY UPDATE

RECENTLY COMPLETED

Affiliate	Approved Increase	Allowed ROE[1] & Equity Thickness	Highlights
Tampa Electric	2022: $191 million USD 2023: $90 million USD 2024: $21 million USD	Midpoint: 9.95% Range: 9.0% - 11.0% Equity: 54.0%	• Full, as filed capital plan, including the Big Bend Modernization, Solar Wave 2, and AMI; • Increase in depreciation and dismantlement expense of US$17M; • Clean Energy Transition Mechanism "CETM" allows for full recovery of retiring assets; • 25 bps increase in ROE range and mid-point (US$10M additional revenue), if U.S. Treasury Bond yields exceed a specified threshold.
Grand Bahamas Power	2022: $3.5 million USD	Target ROE: 12.84%	• Approval for the amortization of the remaining Hurricane Matthew regulatory asset over the three-year period ending December 31, 2024.
Nova Scotia Power Maritime Link	$1.8 billion rate base 2022: $168 million	ROE: Consistent with NSPI Equity: 30%	• 2022 revenue requirement subject to a $2M per month holdback, beginning April 1, 2022, which is dependent upon NS Block flows per month.

ONGOING

- **Barbados Light & Power:** Submitted a general rate review application in October 2021. The application seeks recovery of capital investments, results in annual revenue increase of ~US$23 million, includes a requested ROE of 12.5% and allowed equity structure of 65%. Decision expected by Q2 2022.
- **New Mexico Gas:** On December 13, 2021, NMGC filed a rate case with the NMPRC for new rates to become effective January 2023. NMGC requested a $41 million increase in annual base revenues primarily as a result of increased operating costs and capital investments in pipelines and related infrastructure. A decision is expected by the end of 2022.
- **Nova Scotia Power:** Filed a General Rate Application (GRA) for 2022 through 2024 which includes average non-fuel rate increases of 2.9% per year and average fuel rate increases of 0.8% per year.

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[1] Return on Equity

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NSPI GENERAL RATE APPLICATION ("GRA")

ESSENTIAL STEP ON PATH TO CLEAN ENERGY FUTURE
Address changing weather in NS
Achieve legislated target of 80% renewable by 2030

ROE
No change to midpoint
Range extended to 8.5% - 9.5% (previously 8.75% - 9.25%)

EQUITY THICKNESS
Adjustment to market comparable level - Increase to 45% phased in from 2022-2024

RATE DESIGN – EARNINGS SHARE MECHANISM
50/50 Earnings Share Mechanism above 9.5%

RATE DESIGN - STORM RECOVERY
Storm cost rate rider for level 3 and 4 storms.

DECARBONIZATION DEFERRAL ACCOUNT ("DDA")
Establish DDA to facilitate coal retirement in a cost effective and transparent manner

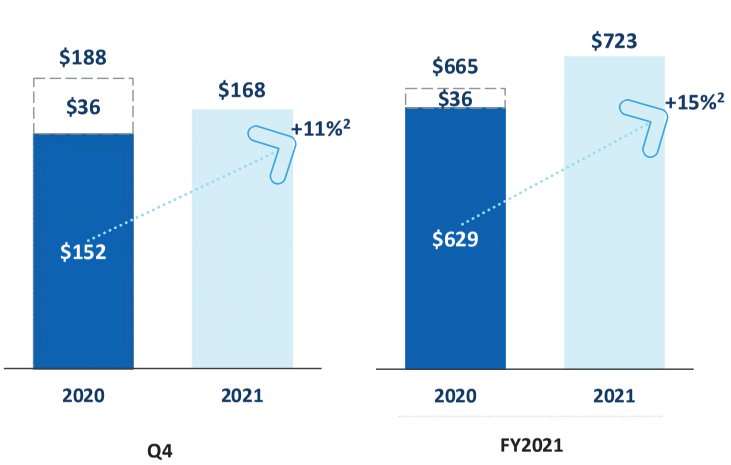
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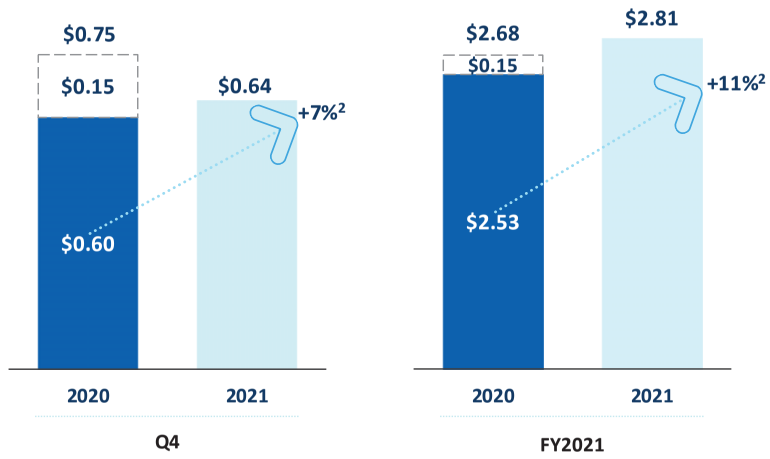
Greg
Blunden
CFO
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FINANCIAL RESULTS
Emera

ADJUSTED RESULTS

Adjusted Net Income[1]



Adjusted Earnings Per Share[1]



[1] Adjusted net income and adjusted earnings per share are non-GAAP measures. See appendix for reconciliation to the nearest GAAP measure.
[2] Excluding the impact of the TGH legal award recognized in Q4 2020 of $36M ($0.15)

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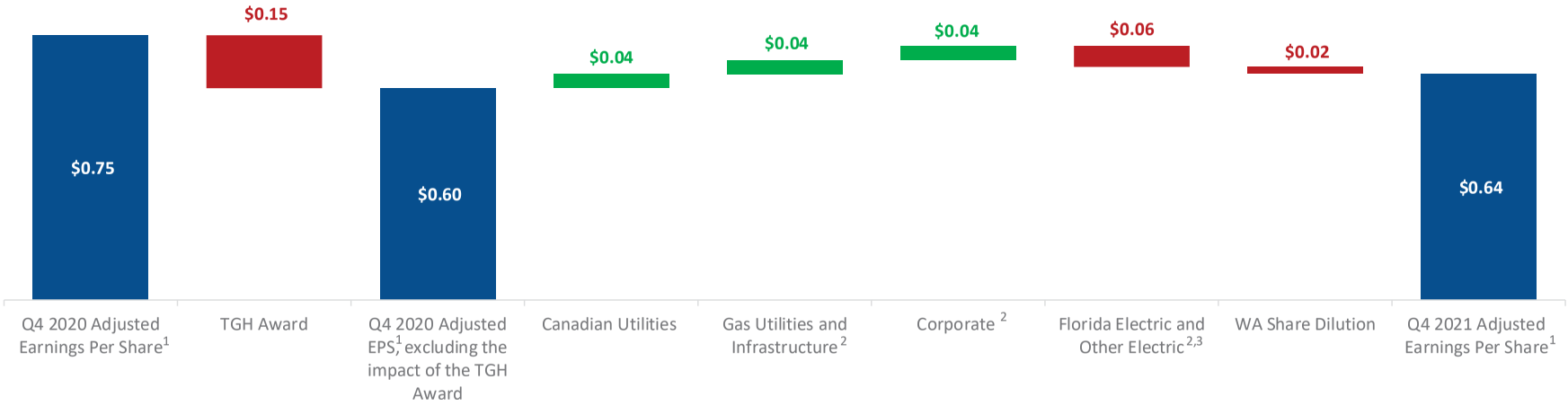
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KEY DRIVERS OF GROWTH IN Q4/21 ADJUSTED EPS[1]

Q4 2021 Adjusted EPS[1]



[1] Adjusted EPS is a non-GAAP measure. See appendix for reconciliation to nearest GAAP measure;
[2] Excludes the impact of foreign exchange;
[3] Includes $0.05 related to Florida Electric, and $0.01 related to Other Electric

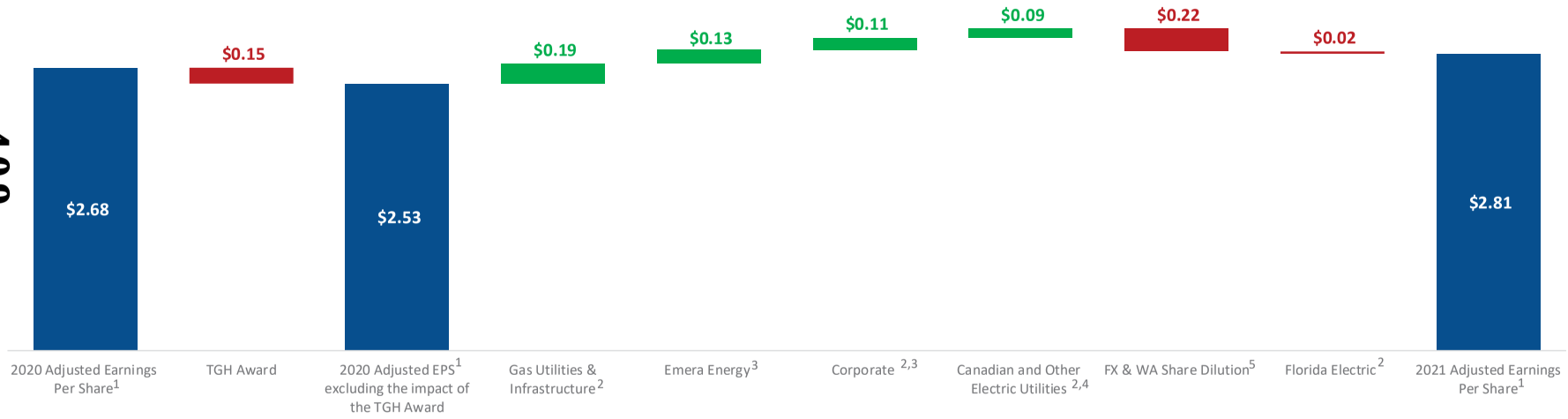
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KEY DRIVERS OF GROWTH IN ANNUAL ADJUSTED EPS[1]

2021 Adjusted EPS[1]



[1] Adjusted EPS is a non-GAAP measure. See appendix for reconciliation to nearest GAAP measure;
[2] Excludes the impact of foreign exchange;
[3] Excludes the impact of one-time tax items in 2020
[4] Includes $0.08 related to Canadian Electric and $0.01 related to Other Electric, excluding Emera Maine
[5] Includes $0.11 related to foreign exchange and $0.11 related to share dilution

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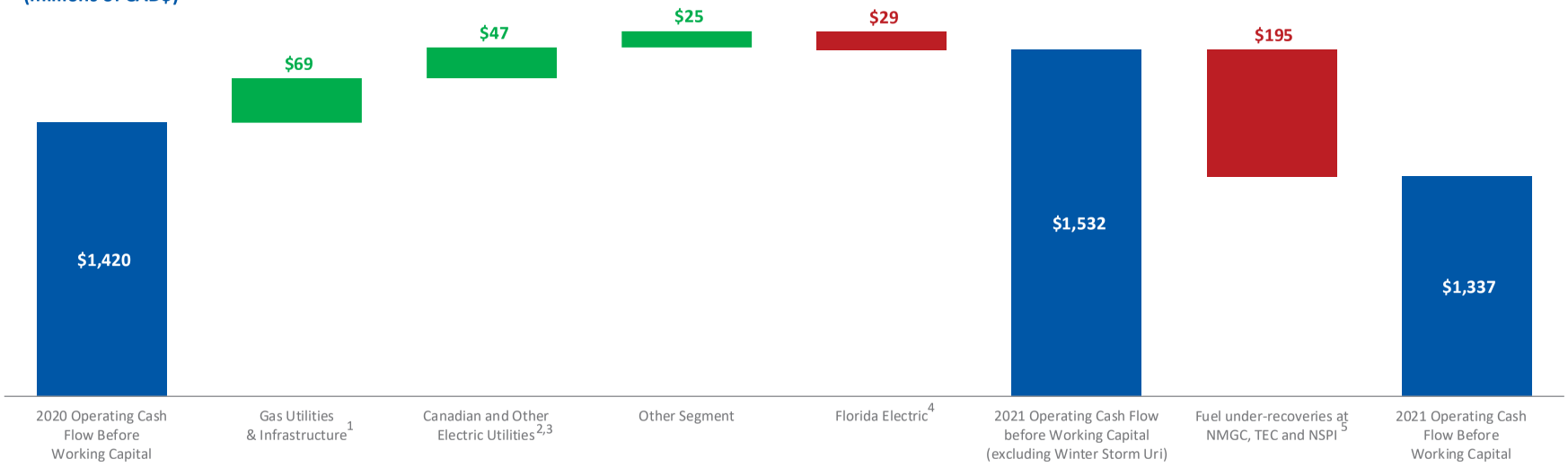
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CASH FLOWS

YTD Operating Cash Flow

Before changes in working capital (millions of CAD$)



[1] Excludes the impact of Winter Storm Uri at NMGC of $110M
[2] Excludes the impact of fuel under-recovery at NSPI of $55M
[3] Excludes the impact of Emera Maine of $18M
[4] Excludes the impact of fuel under-recovery at TEC of $30M
[5] Includes $110M for NMGC, $55M for NSPI and $30M for TEC

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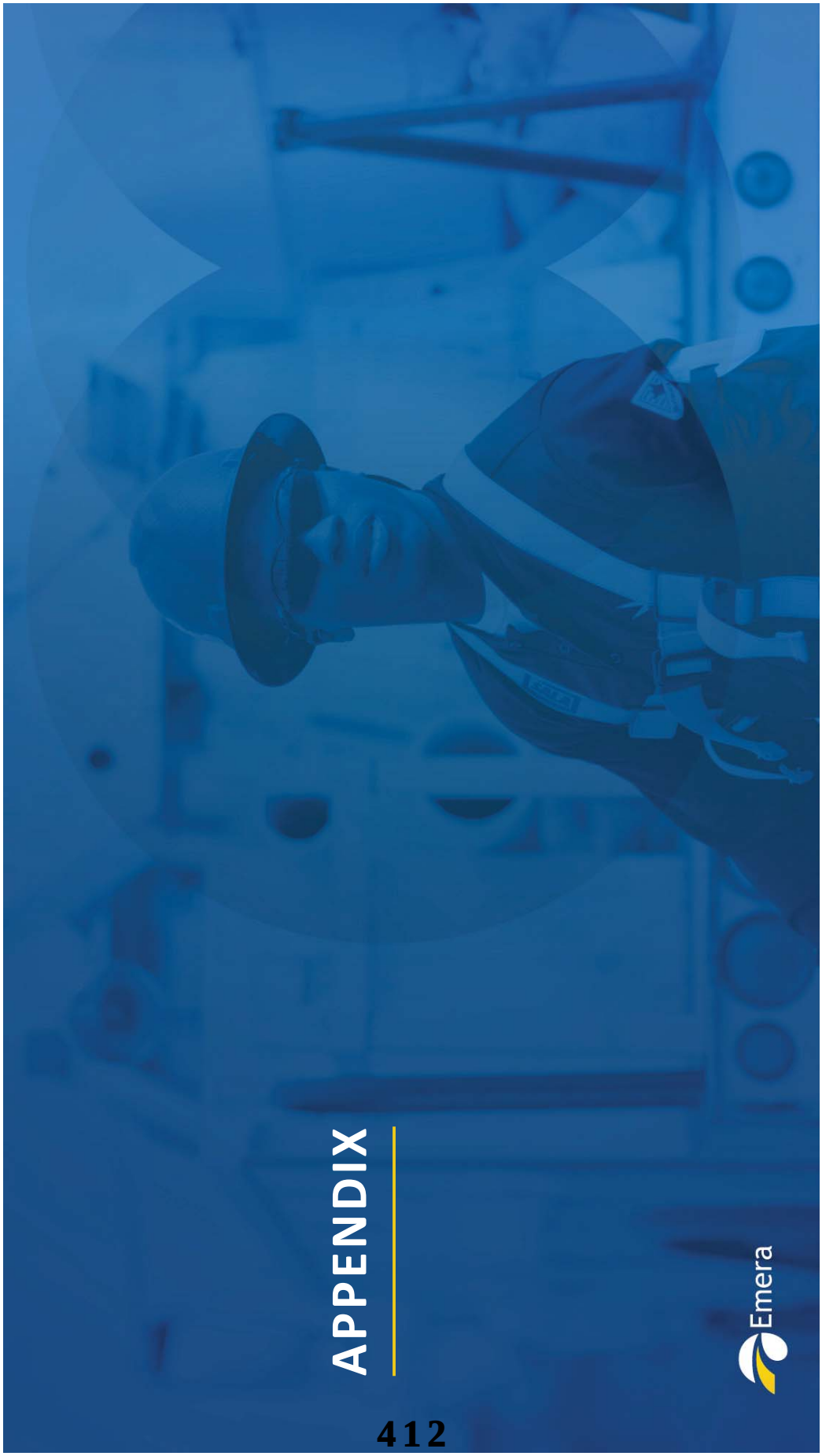
UPCOMING INVESTOR EVENTS

- **Q1/22 Results & Analyst Call**
  May 13, 2022
- **Annual General Meeting**
  May 26, 2022
- **Q2/22 Results & Analyst Call**
  August 2022
- **Q3/22 Results & Analyst Call**
  November 2022



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CAPITAL FORECAST BY AFFILIATE

Capital Forecast[1]	2022F	2023F	2024F	2022-2024 Total
US Operations				
Tampa Electric	$ 1,085	$ 1,180	$ 1,150	$ 3,415
Peoples Gas	270	295	270	835
Seacoast Gas	15	30	30	75
New Mexico Gas	135	140	95	370
Emera Caribbean	100	70	70	240
US Operations Capital Forecast (USD millions)	$ 1,605	$ 1,715	$ 1,615	$ 4,935
FX rate assumption	1.30	1.30	1.30	
US Operations Capital Forecast (CAD millions)	$ 2,085	$ 2,230	$ 2,100	$ 6,415
CAD Operations				
Nova Scotia Power	$ 530	$ 585	$ 585	$ 1,700
Emera Newfoundland	240	-	-	240
Corporate & Other	5	15	5	25
Total Baseline Forecast (CAD millions)	**$ 2,860**	**$ 2,830**	**$ 2,690**	**$ 8,380**
Investments under Development (CAD millions)	10	210	815	1,035
Capital Forecast (CAD millions)	**$ 2,870**	**$ 3,040**	**$ 3,505**	**$ 9,415**

[1] In addition to capital spend, includes $240M of additions to Emera's equity investment in LIL in 2022

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RATE BASE FORECAST BY AFFILIATE

Rate Base Forecast[1]	2020A	2020A Adjusted FX[2]	2021A	2022F	2023F	2024F	2020-2024 CAGR	2020-2024 CAGR Adjusted FX
US Operations								
Tampa Electric[3]	$ 7,760	$ 7,760	$ 8,475	$ 9,190	$ 9,805	$ 10,455	7.7%	
Peoples Gas[3]	1,315	1,315	1,605	1,885	2,105	2,305	15.1%	
Seacoast[4]	140	140	185	185	210	240	14.4%	
New Mexico Gas	635	635	705	785	865	925	9.9%	
Emera Caribbean	725	725	715	835	840	850	4.1%	
US Operations Rate Base (USD millions)	$ 10,575	$ 10,575	$ 11,685	$ 12,880	$ 13,825	$ 14,775	8.7%	
FX rate assumption	1.34	1.30	1.26	1.30	1.30	1.30		
US Operations Rate Base (CAD millions)	$ 14,170	$ 13,750	$ 14,725	$ 16,745	$ 17,975	$ 19,210	7.9%	8.7%
CAD Operations								
Nova Scotia Power	$ 4,225	$ 4,225	$ 4,405	$ 4,775	$ 5,135	$ 5,500	6.8%	
Maritime Link	1,840	1,840	1,780	1,745	1,685	1,630	-3.0%	
Labrador Island Link[5]	605	605	655	800	915	895	10.3%	
Emera New Brunswick[4]	450	450	440	435	425	415	-2.0%	
Baseline Forecast (CAD millions)	**$ 21,290**	**$ 20,870**	**$ 22,005**	**$ 24,500**	**$ 26,135**	**$ 27,650**	**6.8%**	**7.3%**
Investments under Development (CAD millions)	-	-	-	20	130	630		
Rate Base Forecast (CAD millions)	**$ 21,290**	**$ 20,870**	**$ 22,005**	**$ 24,520**	**$ 26,265**	**$ 28,280**	**7.4%**	**7.9%**

[1] Average rate base; [2] USD/CAD exchange rate for 2020 updated to reflect forecasted average rate [3] Capital structures that support the rate base include deferred tax liabilities (DTL), a zero cost-of-capital component of the capital structure in Florida; 2020 capital structures included DTLs of $1,200 million at Tampa Electric and $200 million at Peoples Gas; [4]Reflects the capital asset values of the regulated pipeline investments; [5]Reflects Emera's equity investment in the project

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EMERA ENERGY QUARTERLY ADJUSTED EARNINGS[1] CONTRIBUTION

Millions of Canadian dollars		Q1/20	Q2/20	Q3/20	Q4/20	Q1/21	Q2/21	Q3/21	**Q4/21**
Marketing and Trading	$	19	(11)	(11)	11	37	(3)	(6)	**19**
Maritimes Canada		(2)	-	1	-	1	-	-	**(2)**
Bear Swamp		4	4	(2)	4	5	2	1	**0**
Total Adjusted Net Income[1]	**$**	**21**	**(7)**	**(12)**	**15**	**43**	**(1)**	**(5)**	**17**

Millions of Canadian dollars		2014	2015	2016	2017	2018	2019	2020	2021
Marketing and Trading Adjusted Net Income[1]	$	68	44	22	15	53	5	8	**46**
Average (2014 to 2021)	**$**	**33**							
Average (2014 to 2021) ex. outliers[2]	**$**	**41**							

[1] Adjusted net income is a non-GAAP measure; See appendix for reconciliation to nearest GAAP measure; [2] Excludes 2019 and 2020

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NON-GAAP RECONCILIATION

For the	Three months ended December 31		Year ended December 31	
	2021	2020	**2021**	2020
Florida Electric	**$ 85**	$ 101	**$ 462**	$ 501
Canadian Electric	**67**	57	**241**	221
Other Electric Utilities	**5**	8	**20**	33
Gas Utilities and Infrastructure	**55**	45	**198**	162
Emera Energy	**17**	15	**54**	17
Adjusted earnings before corporate costs	**$ 229**	$ 226	**$ 975**	$ 934
Corporate costs	**(61)**	(38)	**(252)**	(269)
Adjusted earnings attributable to common shareholders	**$ 168**	$ 188	**$ 723**	$ 665
Gain on sale, net of tax and transaction costs[1]	**-**	-	**-**	309
Impairment charges, net of tax[2]	**-**	-	**-**	(26)
After-tax MTM gain (loss)[3]	**156**	85	**(213)**	(10)
Net income attributable to common shareholders	**$ 168**	$ 188	**$ 723**	$ 665

[1] Net of income tax expense of $276 million for the year ended December 31, 2020.
[2] Net of income tax expense of $1 million for the year ended December 31, 2020.
[3] Net of income tax expense of $63 million for the three months ended December 31, 2021 (2020 – $33 million expense) and $86 million recovery for the year ended December 31, 2021 (2020 – $8 million recovery).

Emera

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